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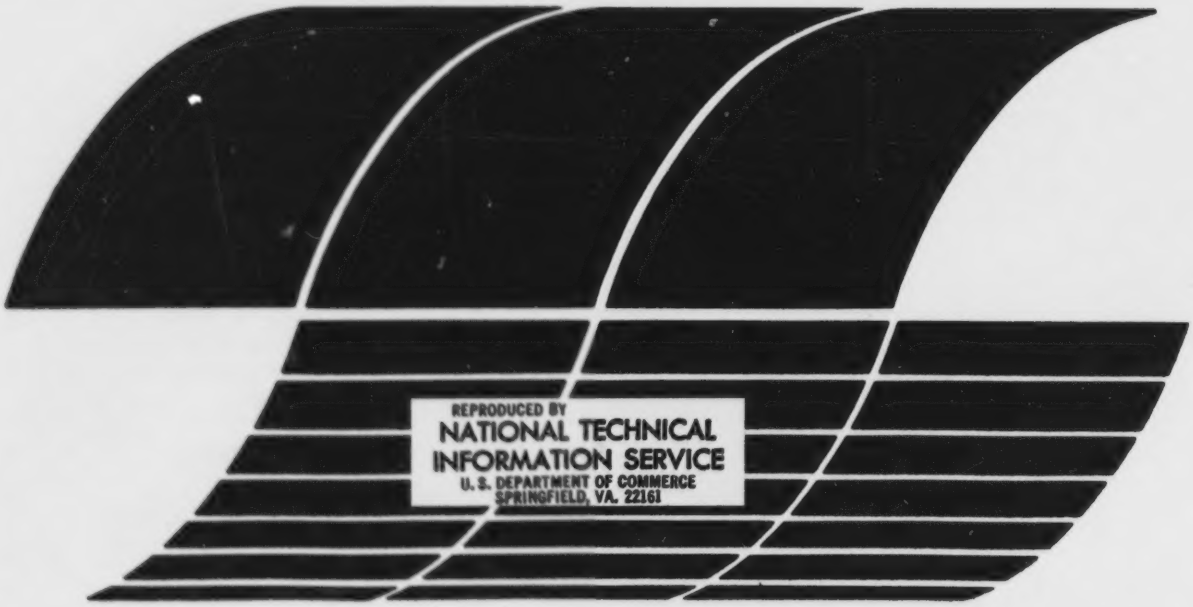

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16. ABSTRACT
The proceedings document the approximately 50 presentations made during the symposium, March 5-8, 1979, in San Francisco. Sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory-RTP, the symposium dealt with subjects relating both to developing improved combustion technology for the reduction of air pollutant emissions from stationary sources, and to improving equipment efficiency. The symposium was in seven parts, and the proceedings are in five volumes: I. Utility, Industrial, Commercial, and Residential Systems; II. Advanced Processes and Special Topics; III. Stationary Engine and Industrial Process Combustion Systems; IV. Fundamental Combustion Research and Environmental Assessment; and V. Addendum. The symposium provided contractor, industrial, and government representatives with the latest information on EPA inhouse and contract combustion research projects relating to pollution control, with emphasis on reducing NOx while controlling other emissions and improving efficiency.

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Joshua S. Bowen, Symposium Chairman,
and
Robert E. Hall, Symposium Vice-chairman

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Office of Research and Development
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PREFACE

These proceedings document more than 50 presentations and discussions presented at the Third Symposium on Stationary Source Combustion held March 5-8, 1979 at the Sheraton Palace Hotel, San Francisco, California. Sponsored by the Combustion Research Branch of the EPA's Industrial Environmental Research Laboratory - Research Triangle Park, the symposium papers emphasized recent results in the area of combustion modification for NO_x control. In addition, selected papers were also solicited on alternative methods for NO_x control, on environmental assessment, and on the impact of NO_x control on other pollutants.

Dr. Joshua S. Bowen, Chief, Combustion Research Branch, was Symposium Chairman; Robert E. Hall, Combustion Research Branch, was Symposium Vice-Chairman and Project Officer. The welcoming address was delivered by Clyde B. Eller, Director, Enforcement Division, U.S. EPA, Region IX and the opening Address was delivered by Dr. Norbert A. Jaworski, Deputy Director of IERL-RTP.

The symposium consisted of seven sessions:

Session I: Small Industrial, Commercial and Residential Systems
Robert E. Hall, Session Chairman

Session II: Utilities and Large Industrial Boilers
David G. Lachapelle, Session Chairman

Session III: Advanced Processes
G. Blair Martin, Session Chairman

Session IV: Special Topics
Joshua S. Bowen, Session Chairman

Session V: Stationary Engines and Industrial Process Combustion Systems
John H. Wasser, Session Chairman

Session VI: Fundamental Combustion Research
W. Steven Lanier, Session Chairman

Session VII: Environmental Assessment
Wade H. Ponder, Session Chairman

VOLUME I

Table of Contents

Session I: Small Industrial, Commercial, Residential Systems

Page

"Evaluation of Emissions and Control Technology for Industrial Stoker Boilers," R. D. Giammar, D. R. Hopper, P. R. Webb, E. Radhakrishan 3

"Field Tests of Industrial Stoker Fired Boilers for Emission Control," J. E. Gabrielson, P. L. Langsjoen 35

"Guidelines for Adjustment of Residential Gas Burners for Low Emissions and Good Efficiency," D. W. Locklin, R. L. Himmel, D. W. DeWerth 59

"Field Verification of Low-Emission Integrated Residential Furnaces," A. S. Okuda and L. P. Combs 81

Session II: Utility and Large Industrial Boilers

"Status of NO_x Control Implementation for Utility Boilers," L. W. Waterland, K. J. Lim and R. J. Schreiber 119

"Field Testing of Utility Boilers and Gas Turbines for Emission Reduction," E. H. Manny, A. R. Crawford, and W. Bartok 157

"Corrosion Testing of Utility Boiler Combustion Modifications," P. S. Natanson, A. R. Crawford, E. H. Manny and W. Bartok 199

"Field Evaluation of Low NO_x Coal Burners on Industrial and Utility Boilers," G. B. Martin 213

"Applicability of the Thermal $DeNO_x$ Process to Coal-Fired Utility Boilers," G. M. Varga and W. Bartok 233

"Combustion Modification Concepts for Stoker Boiler Applications," J. H. Wasser **(Abstract) (See Volume V)** 253

SESSION I

SMALL INDUSTRIAL, COMMERCIAL, RESIDENTIAL SYSTEMS

ROBERT E. HALL
SESSION CHARIMAN

EVALUATION OF EMISSIONS AND CONTROL TECHNOLOGY FOR INDUSTRIAL STOKER BOILERS

by

Robert D. Giammar, David R. Hopper, Paul R. Webb,
and E. Radhakrishnan

BATTELLE
Columbus Laboratories
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Columbus, Ohio 43201

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ABSTRACT

In support of our nation's continual commitment to utilization of coal in an environmentally acceptable manner, EPA has funded a research and development program to identify and demonstrate improvements in stoker-coal firing that can provide an incentive for greater industrial use of coal. The overall objectives of this program are (1) to characterize the spectrum of emissions from industrial coal-fired stoker boilers firing several types of coal under various stoker firing conditions, (2) to investigate control methods to reduce these emissions, (3) to determine the effect of these control methods and variations in stoker-boiler operation on the overall performance of the stoker boiler, and (4) to assess the environmental impact of new technology on the future acceptability of stoker boilers.

This program is divided into two phases. In Phase I, emission characteristics were determined for a variety of coals fired in a 20-bhp stoker. Emphasis was focused on identifying coals with low pollutant potential. These included both physically and chemically treated coals. Phase II is currently being conducted to identify and evaluate potential control concepts for control of emissions from full-scale industrial stoker boilers. The Battelle-Columbus steam plant 25,000-lb steam/hr spreader-stoker boiler is being utilized and modified to evaluate potential control concepts.

In Phase I, it was observed that significant amounts of sulfur were retained in the lignite and western subbituminous coals. Fuel nitrogen conversion to NO was found to be between 10 and 20 percent. In addition, a limestone/high sulfur coal pellet was developed and found effective in capturing 80 percent of the fuel sulfur.

In Phase II, emissions were characterized for several coals under a variety of operating conditions. Firing of the limestone/coal pellet resulted in 75 percent sulfur retention in the ash, thus verifying the results of the small-scale Phase I study. Although there were some minor operational problems in firing the pellet, it can be concluded that the limestone/coal pellet has the potential to be a viable SO_2 control technique for industrial boilers.

ACKNOWLEDGMENT

The research covered in this report was pursuant to Contract No. 68-02-2627 with the U.S. Environmental Protection Agency, Combustion Research Section. The authors acknowledge the assistance of the EPA Project Officer, J. H. Wasser, who participated in planning this program and provided helpful comments. The authors thank other Battelle-Columbus staff who have contributed to this study--R. Coleman, J. H Faught, H. G. Leonard, T. C. Lyons, and the plant facility and operation personnel. In addition, we extend our appreciation to Harold Johnson of Detroit Stoker and several plant engineers who provided us practical guidance.

SECTION I

INTRODUCTION

The stoker-fired boiler provides an option for industry to meet their energy needs. This option has not been exercised by a significant number of industries primarily because oil- and gas-fired equipment have been, and still are, more environmentally and economically attractive. However, with the dwindling supplies of oil and gas, the rising costs of these fuels, and increased attention given to coal utilization, industry once again is considering the stoker coal-fired boiler.

In support of our nation's commitment to cleaning the environment and to utilizing coal, EPA has funded a research and development program* to identify and demonstrate improvements in stoker-coal firing that can provide an incentive for greater industrial use of coal. The overall objectives of this program are (1) to characterize the spectrum of emissions from industrial coal-fired stoker boilers firing several types of coal under various stoker firing conditions, (2) to investigate control methods to reduce these emissions, (3) to determine the effect of these control methods and variations in stoker-boiler operation on the overall performance of the stoker boiler, and (4) to assess the environmental impact of new technology on the future acceptability of stoker boilers.

This program is divided into two phases. In Phase I, emission characteristics were determined for a variety of coals fired in a 20-bhp stoker. Emphasis was focused on identifying coals with low pollutant potential. These included both physically and chemically treated coals. Phase I experiments were conducted to provide some guidance for Phase II, especially in the selection of a "design" fuel, a coal that was physically or chemically treated to make it more environmentally acceptable for stoker firing. Phase II is currently being conducted to identify and evaluate potential concepts for control of emissions from full-scale industrial stoker boilers. The Battelle-Columbus steam plant, 25,000-lb steam/hr spreader-stoker boiler, is being utilized and modified to evaluate potential control concepts.

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* EPA Contract No. 68-02-2627, "Evaluation of Emissions and Control Technology for Industrial Stoker Boilers".

This paper presents the preliminary results of Phase II experiments focused at assessing emission levels for a variety of stoker-boiler system operating variables. Combustion system design modifications as possible control technologies are not addressed here; this aspect of Phase II will be conducted in 1979. A brief summary of Phase I is also included in this paper.

SECTION 2

PHASE I STUDY

The overall performance of a stoker-boiler system and the emissions that it generates are dependent upon a number of factors that include stoker-boiler system design, coal properties, and combustion operating parameters. As a consequence, when comparing emission and performance data from several systems, each of these factors must be taken into consideration. Phase I experiments were conducted in a 20-bhp stoker-boiler facility (Figure 1) described in an earlier EPA report (Reference 1). An underfeed stoker and a custom-built "model" spreader, schematically shown in Figure 2, were both used.

The Phase I experiments were designed to generate data to provide a relative measure of emissions from a variety of coals, including coals that could not be conveniently or economically evaluated in larger industrial systems. For example, in Phase I, chemically and physically treated coals not commercially available as well as coals representative of major reserves in the U.S. were fired. Additionally, it was felt that much of the data would be representative of a variety of units which have been verified by the Phase I experiments in both the underfeed and "model" spreader stokers. Gaseous emissions correlate with coal properties and appear to be somewhat independent of system design. Gaseous emission levels obtained from firing the same coal in both the "model" spreader and an industrial spreader stoker were similar. On the other hand, particulate emission levels appear to be dependent on system design and may not be representative of industrial-size units.

EXPERIMENTAL PROCEDURES

Experimental procedures are similar to those described in Reference 1. Briefly, the stack gas was sampled at the boiler outlet and levels were determined by: paramagnetic analysis for oxygen; nondispersive infrared for carbon monoxide, carbon dioxide, and nitrogen oxide; and a dry electrochemical analyzer for sulfur dioxide. Particulate emissions were measured in a straight section of stack, ten stack diameters downstream of the boiler outlet. Particulate levels were determined by the EPA Method V procedure.

Summary of Significant Findings

Fuel NO--

Table I indicates that a small fraction of the fuel nitrogen is converted to NO (assuming no thermal NO). In comparison to pulverized coal combustion, where as much as 30 to 40 percent of fuel nitrogen is converted to NO, the fuel nitrogen conversion is relatively low for stoker firing. This low conversion may be attributed to the inherent staged combustion of stoker firing accomplished by supplying the total combustion air as primary air through the grates and secondary air through overfire air jets located above the bed. Additionally, as suggested in Reference 2, the relatively high levels of CO that are present in the fuel bed may serve to reduce the NO to N_2.

Fuel Sulfur--

Table II shows the percent fuel sulfur emitted as SO_2 for selected coals. It is well recognized (References 3 and 4) that the alkaline content in the coal can be effective in retaining a portion of the fuel sulfur as sulfate in the ash. Thus, when firing coals with naturally high calcium and sodium content and those treated with these elements, only a portion of the fuel sulfur is emitted as SO_2 as evidenced in Table II.

The measured values of SO_2 were exceptionally low for the lignite and the western subbituminous coals. Maloney in his work (Reference 5) suggests that lime was found more effective in capturing fuel S as sulfide in fuel-rich regions. A representative sample of fuel ash could not be obtained in the 20-bhp stoker facility to verify this observation. However, it was observed that when firing lignite and subbituminous coals, combustion was nonuniform in the fuel bed--a condition that often leads to unburned carbon in the bottom ash.

Limestone was mixed with Illinois No. 6 by two methods. One was simply to introduce limestone (-50 mesh) into the feed system along with stoker-size coal. In the other method, pulverized limestone and coal were mixed together with a suitable binder and then extruded in a mill to form a pellet of about 1/2 in. diameter and 3/4 in. length. The data indicate that the limestone/coal pellets were significantly more effective in capturing sulfur than simply mixing crushed limestone with stoker-size coal. This increased sulfur capture may be attributed to the intimate contact of the limestone with the coal particle in the pellets and possibly the more reactive surface of the pellet.

The hydrothermally treated (HTT) coal is a coal that has been chemically treated to remove sulfur (Reference 6). The process results in some alkali residuals that are effective in capturing some of the remaining fuel sulfur. The HTT coal fired in this study contained about 7 weight percent Ca and 0.5 weight percent Na.

In summary, the Phase I experiments provided gaseous emission data from a variety of coals that appear to agree with those of Phase II. In addition, during Phase I, a limestone/coal pellet was developed that offers potential SO_2 control for industrial boilers.

SECTION 3

PHASE II STUDY

Preliminary results of the Phase II experiments focused at assessing emission levels for a variety of stoker-boiler system operating variables are presented below. These experiments were conducted using the No. 1 spreader-stoker boiler in the central heating plant at Battelle's Columbus Laboratories. A variety of coals that could be conveniently supplied to the test site were fired in addition to the limestone/coal pellets.

FACILITY

The heating plant facility includes a coal-fired stoker utilizing balanced induced draft and forced draft fans for combustion air and a boiler for generating steam. The combustion particulate control system comprises two cyclone dust collectors. The ash from the grate discharge, grate siftings, and cyclone dust collectors are discharged into a hopper which is periodically emptied via dump trucks. Figure 3 is a schematic showing the relative locations of the system components. Sample ports for measuring particulate emission concentrations are located in the exhaust breeching downstream of the induced draft fan while a port for gaseous emission sampling is located between the boiler outlet and induced draft fan. The same type of instrumentation used in Phase I was also used in Phase II.

Stoker

The stoker is a 2A-Hoffman "Firite" Pulsating Ash Discharge (PAD) type with a nominal feed-rate of about 1 ton/hr. The principle of operation of the Hoffman mechanical spreader stoker is to spread coal uniformly on a level, specially designed high resistance grate. The coal is burned in a thin layer on top of the ashes and in suspension.

Coal feed is regulated by changing the length of stroke of the reciprocating feed plates. Length of throw is regulated by the speed of the distributor blades. Uniformity of distribution is a natural consequence of the underthrow principle used exclusively by Hoffman. Distribution is modified by changing the pitch angle of the circular tray.

The grate surface area is 77 sq ft; 11 ft by 7 ft. Incorporated in this area are 18 individual grates. The six grates positioned in the center are 9 in. by 39 in., while the remaining twelve grates located on the sides of the boiler are 12 in. by 39 in. in dimension. The 12-in. wide grates have 4 rows of tubes (16 in each row) and each tube has five 1/4-in. flower-like openings on the grate surface to distribute the air. The 9 in. grates have 3 rows of tubes (16 in each row) with similar holes.

The grate is activated periodically to discharge ashes according to a predetermined time cycle. The time interval between discharge periods is varied manually or automatically. The amount discharged per cycle is adjusted manually to suit the particular type of coal and usually requires no further adjustment for load change.

The grate assembly is energized by a revolving eccentric weight in such a manner that the resulting reciprocating motion or pulsations move the ash bed toward the discharge end. The rotating eccentric weight shaft is driven through speed changing devices either from the line shaft or by a separate motor. The purpose of the speed changer is to adjust for the optimum speed after which the speed setting remains fixed. This adjustment determines the distance the grate moves in each pulsation.

Fly Ash Reinjection System--

Fly ash is collected in hoppers under the boiler passes and is reinjected to the furnace to complete its burning. Nozzles of the Venturi type (Hoffman design) entrain the fly ash using air discharged from the overfire air blower. The fly ash nozzles do not need any special attention except to keep the nozzle piping free and clear. During operation, the minimum air pressure that will insure continuous trouble-free operation is used.

Overfire Air Jets--

There are 4 overfire air jets in the rear and 5 in the front of the furnace. These are located approximately 10 in. above the grate. The maximum overfire air pressure attainable is around 16 in. W.G. The various overfire air jets have individual and branch dampers adjustable by hand. The minimum air pressure is selected that will provide turbulence in the furnace.

Boiler--

The water tube gas/oil fired boiler is a Keeler Type MKB manufactured by E. Keeler Company, Williamsport, Pennsylvania. The boiler was installed at Battelle-Columbus in 1964 and altered for coal firing in 1976. It has an operating pressure of 125 psig with an ASME Power Test Code heating surface of 4119 sq ft utilizing a furnace volume of 1400 cu ft. The boiler can operate at a capacity of 25,000 lb steam per hour, continuous, with a heat release rate of 22,700 Btu/cu ft/hr.

COAL ANALYSES

A variety of coals were fired in Boiler No. 1. The properties of these coals comprising proximate and ultimate analyses, ash fusion temperatures, and size consist are presented in Table III.

RESULTS

Table IV contains a summary of the measured emissions during the Phase II experiments for test firing with the various coals.

Table V outlines the operating variables investigated during the program. These operating variables are discussed with reference to the emission data summary presented in Table IV.

Effect of Operating Variables on Emissions and Boiler Performance

Excess Air--

The effect of different excess air rates was investigated at high load for test firing with the low-S Ohio coal. This was accomplished by varying primarily the underfire combustion air for a constant coal feed rate. It was noted that carbon monoxide (CO) and smoke levels could be controlled by providing adequate excess air to insure complete combustion. However, the limiting factor in the minimum excess air rate was not smoke or CO levels, but clinker formation. Clinkers formed at flue gas O_2 levels around 5.5 percent--CO was around 120 ppm and smoke opacity around 25 percent at this relatively low O_2 condition. Local hot spots which result from uneven distribution of the coal are primarily responsible for clinker formation at the reduced excess air rates.

No appreciable influence on SO_2 emissions was observed for variations in excess air at the full-load condition, while a reduction in NO levels was observed at lower excess air rates. Optimum excess air levels were found to be around 8.0 percent O_2 for the coal fired. Test No. SP-1 (Table IV) represents this optimum condition. Optimum excess air rates were also determined for the other coals fired and these are discussed later.

Overfire Air Rate--

A variety of overfire air/total air flow rate ratios (0 to 0.25) were investigated at full-load operation for test firing of the low-S Ohio coal. Changes in this ratio affected smoke and CO levels. The reduction in smoke levels was much more significant than that in CO at increased overfire air rates.

During the test period, both the rear and front overfire air jets were deactivated. Smoke levels increased to unacceptable levels (about 30 percent opacity) while CO increased from 30 ppm to 50 ppm. NO levels decreased slightly upon deactivating the jets--this can be attributed to several factors including lower above-bed temperatures, reduced oxygen levels, and heterogeneous reduction reactions with smoke particles.

The optimum overfire air rate was about 18.0 percent of the total combustion air, corresponding to 7.5 to 7.7 percent O_2 in the flue gas. For a constant total air flow rate, an increase in the overfire air/total air flow rate ratio above 18 percent would further reduce smoke, but the reduction of underfire air through the bed would create severe clinkering.

Test No. SP-4 (Table IV) was conducted at the optimum overfire air condition. A comparison with Test No. SP-1 shows lower CO and smoke levels at the higher overfire air ratio. Particulate loadings are also lower at the optimum overfire air ratio, revealing that overfire air can reduce particulate emissions by promoting fuel burnout.

Fuel Bed Depth--

Experiments to explore the effects of different bed depths at full load were conducted for test firing with the medium-S Kentucky coal. This coal has a low ash content and a high heating value, properties which were found more suitable for these tests. For higher ash coals, satisfactory combustion could only be achieved over a narrow range of bed depths.

By operating without grate vibration for 3 hours, the bed built up to about 4-1/2 inches. Clinker formation would occur at greater bed depths. With a grate vibrating cycle of 6 minutes, the bed depth could be reduced to about an inch- which is the minimum limit. This limit is imposed by the danger of blowing the insulating ash layer off the grate and exposing the grate metal to the heat of the furnace.

A bed depth of about 2-1/2 inches was found to be optimum and resulted by using a vibrating cycle of 35 minutes for the grate. Test SP-3 (Table IV) which was made at this condition shows that a lower excess air rate (around 7.0 percent O_2) is required for this coal. Sulfur retention--about 10 percent--is lower than that obtained with the low-S Ohio coal (20 to 30 percent). This may be attributed to the lower ash content of the Kentucky coal. Particulate loadings are, however, comparable to that with the Ohio coal--this may be due to factors including the thinner fuel bed, the friable nature of the Kentucky coal, the greater amount of fines present in it, and its higher S content (leading to condensable sulfate formation in the fly ash).

Boiler Loads--

The effect of load on boiler operation was studied for test firings of the low-S Ohio coal. The different loads studied and the corresponding Test Run Numbers (from Table IV) are given below:

1. Full Load -- around 21,000 to 22,000 lb per hr steam
   (Test No.s SP-1 and SP-4)

2. Partial Load -- around 15,000 lb per hr steam
   (Test No. SP-2)

3. Low Load -- around 10,000 lb per hr steam
(Test No. SP-5)

The excess O_2 required at partial load (7.5 percent) was comparable to that at full load, while excess O_2 at low load (11.8 percent) was substantially higher. A greater percentage of overfire air was required at lower loads to maintain a clean stack and reduce excessive CO emissions.

Bed temperatures were around 2575 F at full load, 2450 F at partial load, and about 2200 F at low load.

NO levels were not measured during all four tests--the difference in NO emissions for Runs SP-4 and SP-5 is not significant. SO_2 emissions are comparable at partial and full load conditions, but about 15 to 20 percent lower at the low-load condition. This result appears to be verified by the thermodynamic prediction (References 5 and 7) that S retention in bed ash increases with decreasing temperatures below 2500 F and increasing excess air, conditions associated with low-load operation. A comparison of dust loadings in Tests SP-1, SP-2, and SP-5 shows a trend of increasing particulates with increasing boiler load. This is probably due to an increased rate of fly ash carryover at higher underfire air rates required for higher loads.

Boiler efficiencies were not significantly different at the various loads--these were 78 percent, 76 percent, and 75 percent, respectively, at full, partial, and low load.

A significant achievement of the low load experiments was the alleviation of the low-load smoke problem. This was achieved by supplying a controlled amount of underfire air to the bed. At high underfire air settings, smoke formation occurs due to incomplete combustion resulting from local quenching of the flame by the combustion air. However, there is a minimum level of excess air that is required to avoid clinker formation. Smoke levels below 5 percent opacity were achieved for low-load operation at excess air levels around 12.0 percent oxygen (Test No. SP-5). It must be pointed out that the attention and skill of the boiler operator are important factors in controlling low-load smoke, as smoke levels can increase suddenly and drastically for any changes in boiler load or operation.

Fly Ash Reinjection--

The effect of fly ash reinjection on particulate emissions and combustion efficiency was investigated for test firing with the following coals:

1. Low-S, washed Kentucky coal (Test Nos. SP-11, SP-12)
2. High-S, washed run-of-the-mine Ohio Coal (Test Nos. SP-13, SP-14)
3. High-S, washed stoker-grade Ohio coal (Test Nos. SP-15, SP-16).

The runs during which fly ash reinjection was practiced correspond to Test Nos. SP-11, SP-14, and SP-16, while no fly ash was reinjected during Tests SP-12, SP-13, and SP-15. Furthermore, only about 65 percent of the total fly ash was reinjected during the fly ash reinjection runs for the high-S Ohio coals. Each coal was fired with and without fly ash reinjection under approximately the same boiler operating conditions--full load (21,000 to 22,000 lb per hr steam) was maintained during these runs.

No significant trend in gaseous emissions was observed, while a reduction in smoke was observed for runs made without fly ash reinjection. The effect on smoke is, however, difficult to determine as smoke levels under all conditions were below 5 percent opacity.

The most significant effect was the reduction in particulate loadings without fly ash reinjection, as shown in Table VI. These results suggest that particulate loadings may be reduced by 10 to 25 percent by operating the spreader-stoker boiler without fly ash reinjection. Table VI also shows that the carbon loss by not reintroducing the fly ash is less than 1-1/2 percent of the total carbon input. With fly ash reinjection, the carbon loss is about 3 percent of the total carbon input with certain coals.

These results, plus the fact that portions of the fly ash reinjection system have to replaced periodically due to erosion, make fly ash reinjection unattractive for the Battelle boiler.

Coal Types--

With the exception of the unwashed stoker Ohio coal, and to a certain extent, the Illinois No. 6 coal, the other coals were fired satisfactorily. The high ash content of the unwashed stoker coal and the high moisture content of the Illinois No. 6 coal are partly responsible for the problems encountered in firing them. The high amount of fines present in these coals added to the difficulty in firing them.

The Kentucky and the low-S Ohio coals were superior to the high-S stoker-grade and run-of-the-mine coals in terms of SO_2, NO, and particulate emissions. Moreover, as Table IV shows, they could be fired at lower excess air rates.

Sulfur oxide emissions are largely a function of the sulfur in the fuel. It appears that Ohio coals with less than 0.7 percent S and Kentucky coals with less than 1.25 percent S would meet the Federal SO_2 emission standard of 1.2 lb/mBtu. Again, Table IV reveals that some of the eastern Bituminous coals have a sulfur capture efficiency around 25 percent at full-load operation.

Nitric oxide emissions were low and below 0.6 lb/mBtu for all fuels tested. Conversion of fuel nitrogen to NO (assuming no thermal NO) was around 12 to 20 percent (Table II), similar to that seen in the Phase I study.

Particulate emissions were close to or below the Ohio EPA regulation of 0.24 lb/mBtu during test firing of the low-S Ohio and the Kentucky coals. However, as can be seen from Table IV, they were much higher for the high-S Ohio coals. Analyses of the fly ash emitted from firing the high-S coals show a higher percentage of sulfate, signifying that an appreciable quantity of condensable sulfates may be present in the fly ash from these coals.

Table IV shows that CO emissions were low for all fuels tested (with the exception of the limestone/coal pellet) and less than 120 ppm at 3 percent O_2.

Boiler efficiencies were around 76 percent for the low-S Ohio coal, around 84 percent for the medium-S Kentucky coal, 71 to 74 percent with the high-S washed coals, and 68 percent for the unwashed stoker coal. This shows that boiler efficiencies are appreciably higher for the low-moisture, low-ash Kentucky coal. Combustion losses also appear to be lower for this fuel.

Limestone/high-S coal pellet--The limestone/high-S coal pellets, which showed potential for sulfur capture in the Phase I experiments, were fired in the 25,000 lb steam/hr stoker. Test Nos. SP-18 and SP-19 represent the pellet runs. The limestone/coal pellets were found to possess a sulfur capture efficiency of about 75 percent. Some operational problems were encountered in maintaining a stable bed due to the high percentage of ash (≈50 percent) in the pellet. Also, a fairly high excess air rate (around 11.0 percent O_2) had to be supplied to maintain clinkerless operation.

The limestone/coal pellet developed for this study offers a potentially interesting and exciting new means of sulfur control for industrial boilers. The use of limestone for capturing sulfur is by no means new. Exactly how and why limestone should be effective in capturing sulfur on a stoker bed is not well established at this time. Thermodynamically, one would guess that the coal bed is much too hot to retain sulfur as calcium sulfate. On the other hand, it is possible that the stoker bed is a very nonuniform combustion mixture. In such a state, one might anticipate significant lean air regions or areas. As such, it is conceivable that reduced conditions may exist in parts of the bed which ultimately lead to sulfur capture via sulfide formation. This is also an explanation offered by Maloney, et al, in their recent study. At this stage one must only consider this as a hypothetical explanation since the overall bed analyses tend to show little sulfide present. These speculations notwithstanding the use of limestone/coal pellets merit serious attention as viable alternative means for controlling SO_2.

From an industrial point of view, the possibilities of using limestone/coal pellets for removing SO_2 in situ via a dry process is considered more inviting than the use of scrubbers. The additional costs for pelletizing the coal mixture and for the removal of possibly twice as much ash is far more attractive than the high cost of operating and maintaining wet scrubbers.

SECTION 4

SUMMARY OF PHASE II RESULTS

The Phase II experiments have demonstrated that emission levels can be reduced by proper control of the stoker operating variables. In addition, the limestone/coal pellets have been demonstrated to offer potential control for SO_2. In summary, the major findings are:

- The limestone/high-sulfur coal pellet showed a sulfur capture of about 75 percent.
- Sulfur capture efficiencies of around 25 percent were noticed with some eastern bituminous coals.
- High excess air rates at low loads result in increased sulfur retention in the bed ash.
- CO and smoke levels can be controlled by providing adequate excess air. CO levels were low for all fuels tested.
- Clinker formation may be a limiting factor in determining the minimum excess air rate.
- NO levels increase slightly with increase in excess air.
- Conversion of fuel nitrogen to NO was between 12 to 20 percent, assuming no thermal NO.
- An increase in overfire air/total air flow rate ratio reduces CO and smoke, the latter more significantly. Particulate loadings are also lower with increased overfire air.
- NO is lower for operation with inactive jets.
- Clinker formation occurs readily if bed depths become excessive, while the danger of burning the grates exists for operation with very thin beds. Bed depths around 2.5 to 3.0 inches appear to be optimum for lower ash coals.

- A higher excess air rate is required for low-load than for partial- or full-load operation. A greater percentage of overfire air is required at low load. Low load smoke can be reduced by a reduction in underfire air, coupled with attentive boiler operation.

- Particulate loadings may be reduced by 10 to 25 percent by operating at full load without fly ash reinjection. Fuel savings of less than 1.5 percent were observed for operation with fly ash reinjection.

- The high-S Ohio coals had to be fired at higher excess air rates than with the low-S Ohio and Kentucky coals. The high-ash unwashed stoker coal and high-moisture Illinois No. 6 coal could not be fired satisfactorily.

SECTION 5

CONVERSION FACTORS

This report has been prepared using English engineering units. Table VII provides factors for conversion to SI units, if desired.

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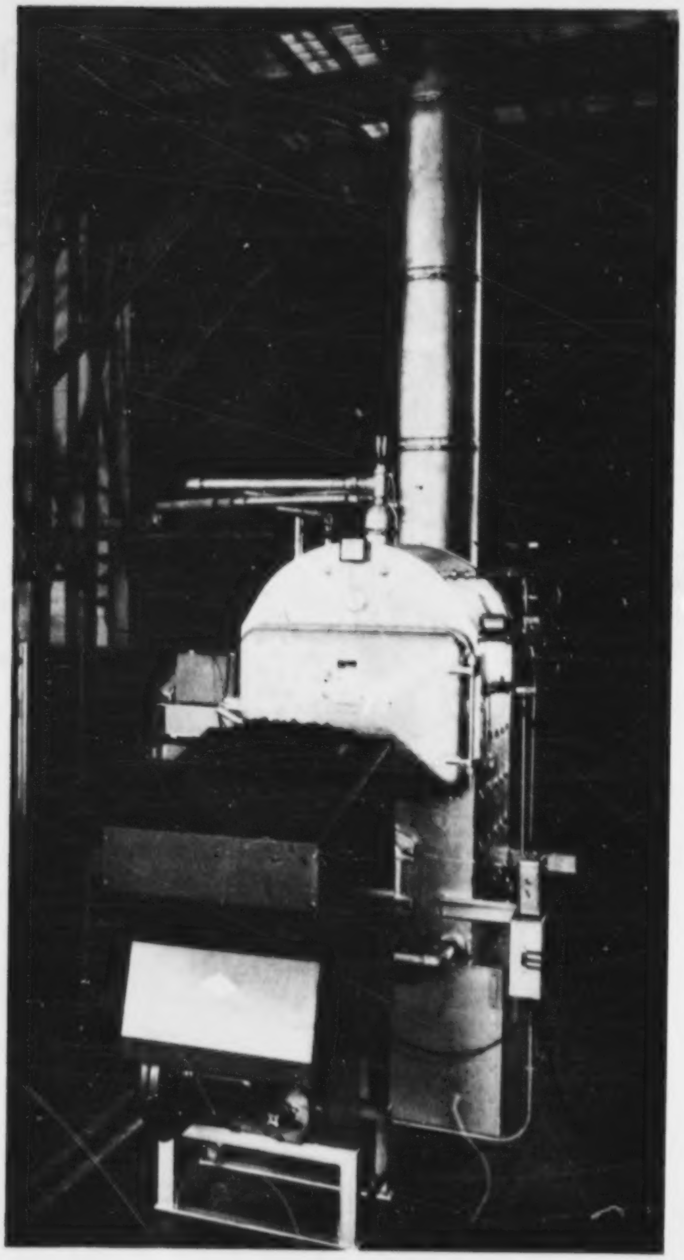

Figure 1. 20-bhp Stoker-Boiler Facility

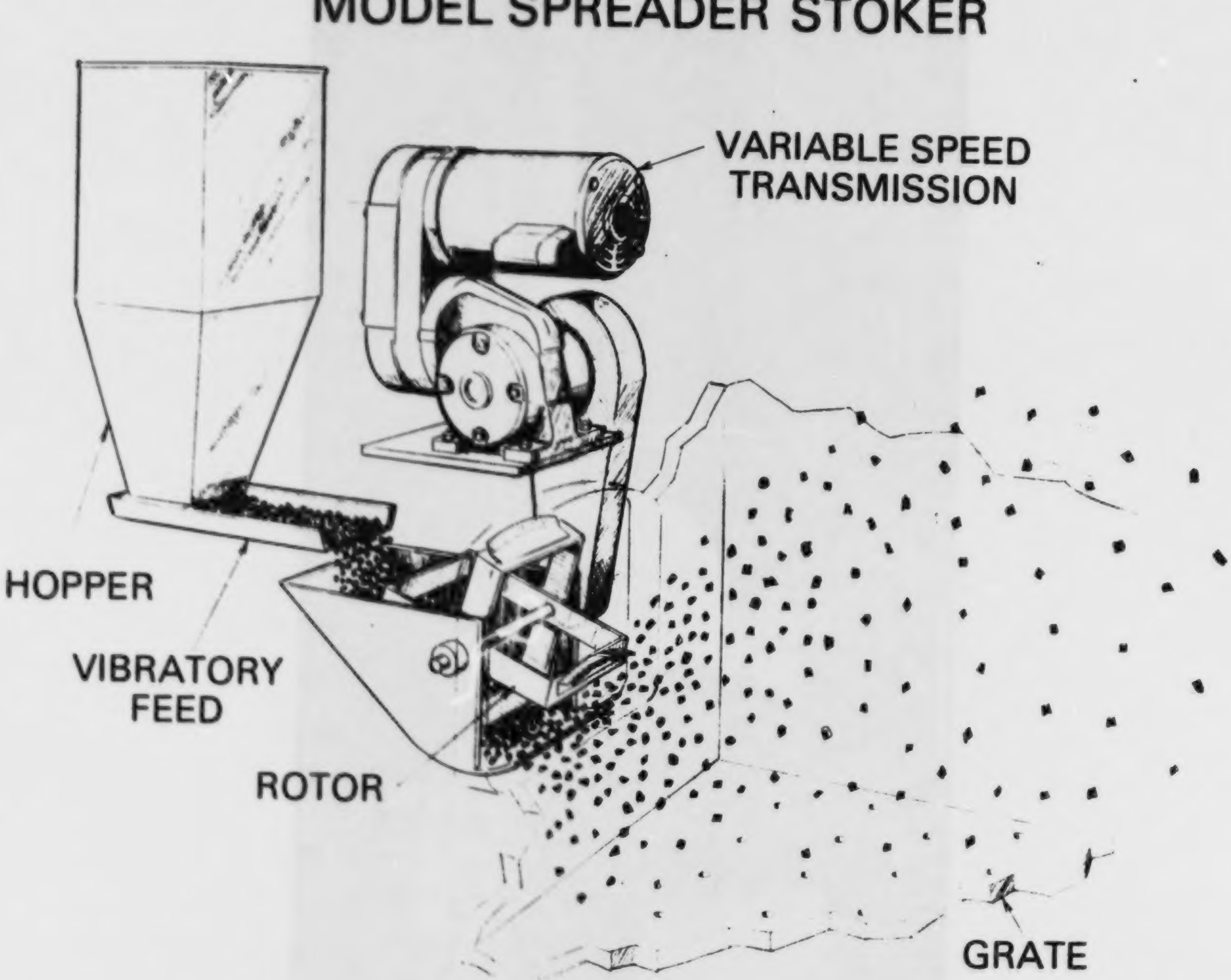
MODEL SPREADER STOKER
VARIABLE SPEED TRANSMISSION
HOPPER
VIBRATORY FEED
ROTOR
GRATE

Figure 2. Model Spreader Stoker

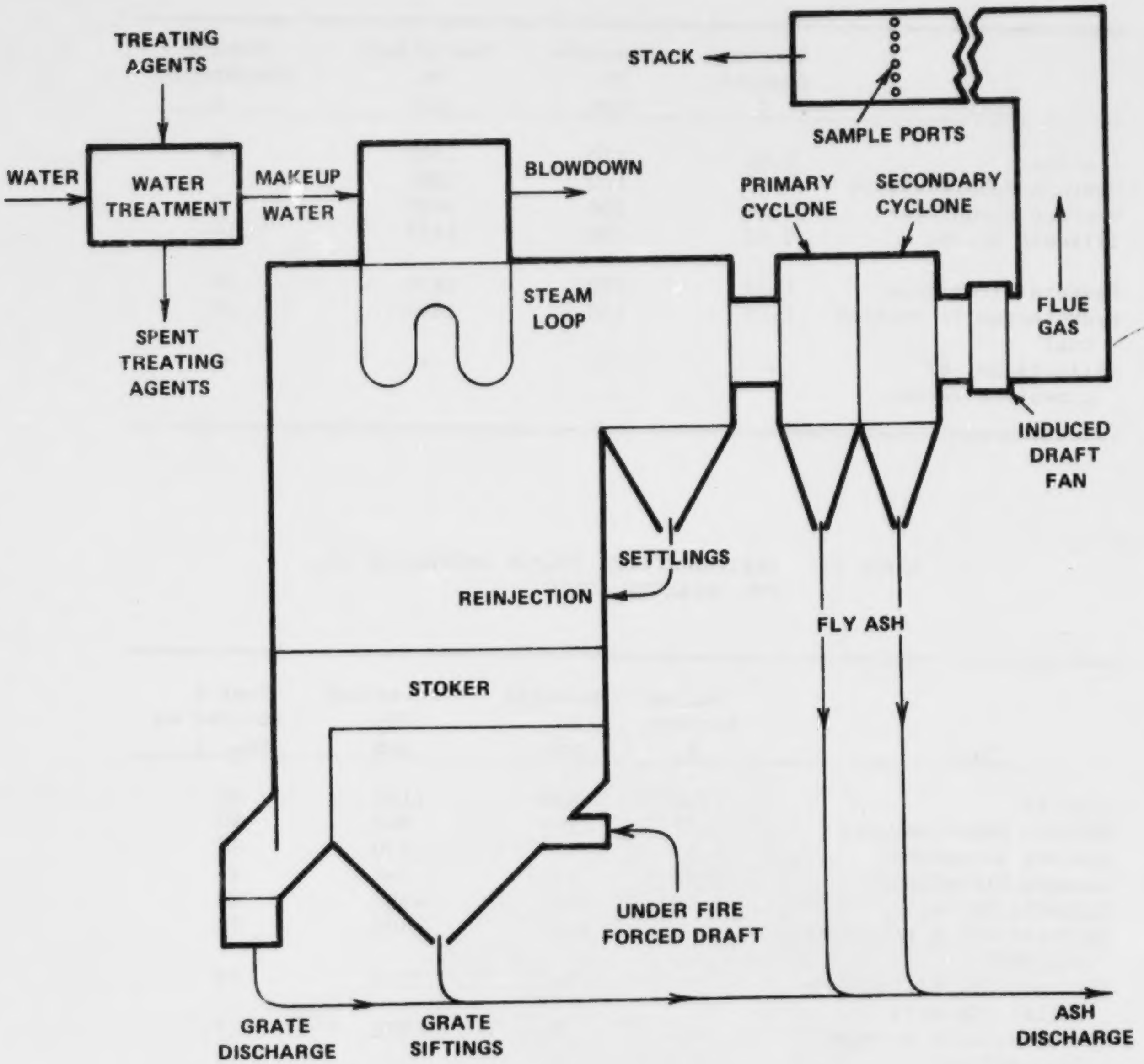
TREATING AGENTS
WATER
WATER TREATMENT
MAKEUP WATER
SPENT TREATING AGENTS
BLOWDOWN
STEAM LOOP
STACK
SAMPLE PORTS
PRIMARY CYCLONE
SECONDARY CYCLONE
FLUE GAS
INDUCED DRAFT FAN
SETTLINGS
REINJECTION
FLY ASH
STOKER
UNDER FIRE FORCED DRAFT
GRATE DISCHARGE
GRATE SIFTINGS
ASH DISCHARGE

Figure 3. Schematic of 25,000 lb steam/hr
Stoker-Boiler Facility

TABLE I. CONVERSION OF FUEL NITROGEN TO NO FOR SELECTED COALS (assuming no thermal NO)

Coal	Nitrogen Content, %	Measured NO, ppm	Theoretical NO, ppm	Fuel N Conversion, %
Lignite	0.61	120	1500	8
Western Subbituminous	0.60	160	1800	
Western Bituminous	1.40	200	2400	8
Illinois No. 6	0.93	200	1450	14
Eastern Bituminous	1.30	270	1800	14
Hydrothermally Treated Coal	1.10	180	1850	10
Illinois No. 6/ Limestone Pellet	--	--	--	--

TABLE II. AVAILABLE FUEL SULFUR EMITTED AS SO_2 FOR SELECTED COALS

Coal	Sulfur Content, %	Measured SO_2, ppm	Theoretical SO_2, ppm	Fuel S Emitted as SO_2, %
Lignite	1.10	350	1100	32
Western Subbituminous	0.67	560	940	60
Western Bituminous	0.55	400	450	89
Eastern Bituminous	1.20	720	740	97
Illinois No. 6	4.40	3800	4100	93
Illinois No. 6 w/Limestone (Ca/S=7)	--	3200	4100	78
Illinois No. 6/Limestone Pellet (Ca/S=7)	--	560	2910	19
Hydrothermally Treated Coal Pellet	1.10	220	820	27

TABLE III.

	Proximate Analysis, % (as received)		Ultimate Analysis, % (as received)			
Fuel Type	Volatiles	Fixed Carbon	Ash	Moisture	Carbon	Hydrogen
Low-S Ohio Coal	33.12	47.59	9.60	9.69	64.81	4.26
Medium-S Kentucky Coal	38.20	53.15	4.95	3.70	76.96	5.15
Stoker-Grade, Washed Ohio Coal	37.84	42.58	10.34	9.24	63.40	4.54
Stoker-Grade, Unwashed Ohio Coal	36.34	40.95	18.50	4.21	59.98	4.23
Run-of-the-Mine, Washed Ohio Coal	38.89	43.47	8.60	9.04	65.02	4.56
Low-S Kentucky Coal	36.87	52.83	7.71	2.59	75.42	5.03
Illinois No. 6	37.30	39.97	8.63	14.10	60.52	4.23
Limestone/High-Sulfur Coal Pellet	39.20	NA*	45.60	12.60	29.70	1.54

* NA - Not Available.

SUMMARY OF COAL ANALYSES

Ultimate Analysis, % (as received)							
Nitrogen	Chlorine	Sulfur	Oxygen (difference)	Heating Value (as recd.) Btu/lb	Ash-Fusion Temperatures, F (Initial Deformation) Reducing	Ash-Fusion Temperatures, F (Initial Deformation) Oxidizing	Fuel Size Consist (% less than 1/8")
1.26	0.05	0.70	9.63	11,473	NA	2700+	7
1.26	0.14	1.38	6.46	13,786	2125	2450	12
1.21	0.06	3.00	8.21	11,452	2045	2470	6
1.09	0.06	3.94	7.99	11,009	2080	2485	17
0.98	0.04	3.19	8.57	11,732	2005	2400	16
1.53	0.11	0.89	6.72	13,480	2480	2700	12
1.10	0.14	3.46	7.82	10,903	2020	2310	6
0.48	--	1.96	8.64	4,257	NA*	NA*	NA*

TABLE IV. EMISSION DATA SUMMARY FROM PHASE II EXPERIMENTS--

				Flue Gas Composition					
Test No.	Coal Type	Load, 10^3 lb /hr	Overfire Air / Total Air	O_2, %	CO_2, %	CO, ppm	SO_2, ppm	NO, ppm	Smoke Opacity, %
SP-1	Low-S Ohio	21.5	0.14	8.0	11.0	50	360	--	10
SP-2	Low-S Ohio	14.5	0.23	7.5	11.4	60	350	—	4-5
SP-3	Medium-S Kentucky	21.0	0.16	7.0	12.4	34	700	—	7
SP-4	Low-S Ohio	21.0	0.18	7.7	13.0	25-30	320	230	4
SP-5	Low-S Ohio	9.5	0.32	11.8	8.4	70	190	185	5
SP-6	Stoker-grade, washed Ohio	21.5	0.17	8.0	11.2	28-44	1800	280	6
SP-7	Stoker-grade, unwashed Ohio	21.0	0.15	10.8	9.0	32-72	2200	250	7-11
SP-8	Run-of-the-mine, washed Ohio	21.0	0.17	9.0	10.5	40-72	1800	230	6-9
SP-9	Stoker-grade, washed Ohio	22.5	0.16	9.4	10.1	40-68	1400	240	6
SP-10	Run-of-the-mine, washed Ohio	22.0	0.18	9.0	10.8	35-50	1900	245	6
SP-11	Low-S Kentucky	22.5	0.18	8.5	10.4	35-45	340	250	4
SP-12	Low-S Kentucky	22.0	0.16	8.8	10.4	25-35	330	235	2
SP-13	Run-of-the-mine, washed Ohio	20.0	0.17	9.3	9.8	30-45	1500	250	3
SP-14	Run-of-the-mine, washed Ohio	20.5	0.19	9.8	9.4	40-68	1300	240	4
SP-15	Stoker-grade, washed Ohio	20.0	0.18	10.0	9.8	20-35	1350	230	2
SP-16	Stoker-grade, washed Ohio	21.0	0.19	9.2	10.2	20	1700	260	3
SP-17	Illinois No. 6	17.0	0.19	9.5	10.2	36-40	1900	230	5
SP-18	Limestone/high-S coal pellet	16.0	0.13	11.2	10.0	420-600	560	145	22
SP-19	Limestone/high-S coal pellet	15.0	0.16	11.8	9.5	1000	515	140	25

BATTELLE'S 600-bhp SPREADER STOKER

CO at 3% O_2, ppm	SO_2 at 3% O_2, ppm		Fuel S Emitted, %	NO at 3% O_2, ppm		% Conversion of Fuel N to NO	Particulates, lb/mBtu
	Computed into System	Measured Emissions		Computed into System	Measured Emissions		
70	625	505	80.8	2565	--	--	0.26
80	625	470	75.2	2565	--	--	0.18
44	1010	910	90.1	2110	--	--	0.25
34-41	625	440	70.4	2565	320	12.5	0.17
140	625	375	60.0	2565	365	14.2	0.15
38-60	2635	2475	93.9	2430	385	15.8	0.45
52-120	3650	3635	99.6	2310	413	17.9	--
60-80	2750	2740	99.6	1930	350	18.1	0.55
63-107	2635	2192	83.2	2430	375	15.4	0.51
52-75	2750	2825	(102.7)	1930	365	18.9	0.67
50-65	665	490	73.7	2615	360	13.8	0.17
37-52	665	488	73.4	2615	350	13.4	0.13
60-70	2750	2310	84.0	1930	385	19.9	0.36
65-110	2750	2092	76.1	1930	386	20.0	0.40
33-58	2635	2230	84.6	2430	380	15.6	0.37
31	2635	2602	98.7	2430	398	16.4	0.41
57-63	3190	2974	93.2	2320	360	15.5	--
792-1132	4035	1057	26.2	2255	274	12.2	1.43
2010	4035	1035	25.6	2255	281	12.5	2.24

TABLE V. OPERATING VARIABLES STUDIES FOR SYSTEM CHARACTERIZATION IN PHASE II

- EXCESS AIR
  - Minimum levels
  - Optimum operating levels from both an emissions and efficiency viewpoint
- OVERFIRE AIR RATE
  - Jets inactive
  - Optimum rate from an emissions viewpoint
- FUEL BED DEPTH
  - Maximum
  - Minimum
  - Optimum
- BOILER LOADS
  - Low load (30 to 40 percent of full load)
  - Partial load
  - Full load
- FLY ASH REINJECTION
  - Maximum
  - Partial
  - None
- COAL TYPES
  - Size distribution
  - Ash content
  - Ash-fusion properties
  - Sulfur levels
  - Treated coal: limestone/coal pellet

TABLE VI. EFFECT OF FLY ASH REINJECTION

Type of Coal	Particulate Loading, lb/mBtu w/ Fly Ash Reinjection	Particulate Loading, lb/mBtu w/o Fly Ash Reinjection	Percent Reduction in Particulate Loadings	Percent Increase in C Loss
Kentucky	0.17	0.13	23.5	1.0
Run-of-the-Mine Ohio	0.40	0.36	10.0*	1.3
Stoker-Grade Ohio	0.41	0.37	9.8*	0.5

* Around 65 percent of total fly ash was reinjected during the fly ash reinjection runs.

TABLE VII. ENGLISH AND METRIC UNITS TO SI UNITS

To Obtain	From	Multiply By
ng/J	lb/10^6 Btu	430
ng/J	g/Mcal	239
m	ft	0.3048
cm	in.	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
kg	lb	0.4536
Celsius	Fahrenheit	$t_c = 5/9 (t_F - 32)$
Kelvin	Fahrenheit	$t_K = 5/9 (t_F - 32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895 \times 10^3)$
Pa	iwg (39.2 F)	$P_{pa} = (P_{iwg})(249.1)$
MW	10^6 Btu/hr	0.293

FIELD TESTS OF INDUSTRIAL STOKER FIRED BOILERS FOR EMISSION CONTROL

BY

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ABSTRACT

A program funded by the Department of Energy and the U. S. Environmental Protection Agency is underway to produce information which will increase manufacturers ability to design and apply stokers and boilers which are an economical and environmentally satisfactory alternative to importation and combustion of fuel oil which may not be available in the event of a national emergency. Initially, the program was to test six spreader stokers, but it has been expanded to also include five mass fed stokers.

To date, three boilers with spreader stokers and one with a Vibra-Grate Stoker have been tested under this ongoing program. Some of the preliminary findings are presented in this paper. Emissions and efficiency are reported as functions of amount and geometry of overfire air admission, degree of flyash reinjection, excess air level, coal properties, air velocity through the grate and the two types of stokers are compared. Measurements include particulate mass loading at both the boiler outlet and the mechanical collector outlet, oxides of nitrogen, excess oxygen and carbon monoxide. Combustible and dry gas heat losses are also discussed.

INTRODUCTION

In recent years the vast majority of industrial boiler installations have been shop assembled gas and oil fired units which could be purchased and installed at substantially lower cost than conventional coal burning boiler-stoker equipment. Because of the decline in the coal firing market areas for equipment manufacturers, little or no work has been done in recent years to develop cleaner burning stoker fired boilers. Just as important, updated emission specification data have not been made available to consulting engineers and purchasers of coal burning equipment. The implementation of more rigid air pollution regulations coupled with the lack of good boiler emission data has had a further negative influence on the installation of coal burning installations. It is difficult for many coal burning installations to comply in a cost effective manner with required stack emission limits.

The national interest in coal utilization has increased dramatically within the last few years. As a result, the Department of Energy (DOE) and the Research Branch of the Environmental Protection Agency (EPA) are co-funding a test program whose objective is to develop information which will increase manufacturers ability to design and apply stoker fired boilers which are an economical and environmentally satisfactory alternative to importation and combustion of fuel oil which may be in short supply in the event of a national emergency. The American Boiler Manufactuers Association (ABMA) is managing the test program through its Stoker Technical Committee. KVB, Inc., a combustion consulting firm, is performing the testing.

The scope of this program covers testing of eleven stoker fired boilers in the size range of 20 to 90 MW (75,000 to 300,000 lb/hr steam flow). Only new "state-of-the-art" stoker fired boilers are being tested. By comparison of test data between various units, design specifications will be updated. Primary emphasis is on particulate loading and sizing at the boiler outlet and after any ash reinjection device. Emissions and efficiency are being determined as functions of overfire air admission, degree of flyash reinjection, excess air, coal sizing and analysis, grate air velocity, etc., for various boiler-stoker designs. Technical reports on test results for each individual boiler tested and the final technical report at the conclusion of this program will be made available to the public through the National Technical Information Service (NTIS). The reports will also be available through EPA, DOE, ABMA and KVB.

This paper will present some of the initial results of testing on the first four boilers tested under the program entitled, "A Testing Program to Update Equipment Specifications and Design Criteria for Stoker Fired Boilers," DOE Contract No. EF-77-C-01-2609.

TEST RESULTS

OVERFIRE AIR

Overfire air jets were originally installed above the fuel bed on stoker boilers to promote mixing of the product gases in the flame zone, increase combustion and reduce smoke. Overfire air systems have undergone numerous modifications over the years. Very little hard test data which detail the impact of overfire air on particulate and ntiric oxide emissions and boiler efficiency are available to the public.

With the goal of establishing the effectiveness of overfire air, overfire air tests have been run on the first four boilers tested under the program described above. In each case, particulate loading at the boiler outlet was reduced by increasing the quantity of overfire air. Figure 1 illustrates the reduction in particulate loading resulting from an increase in overfire air pressure from 750 Pa (3 iwg) to 2500 Pa (10 iwg) at three boiler loads. The unit tested was an 87 MW (300,000 lb/hr) spreader stoker having two rows of overfire air jets on both the front and rear water walls. In these tests, particulate loading reductions of 25 to 50% were experienced. This reduction was found to be due primarily to burnout of combustibles in the flyash and resulted in a 0.8 to 2.0% increase in combustion efficiency.

In similar tests run on a 62 MW (200,000 lb/hr) spreader stoker, 25% reductions in particulate loading were measured. On a 66 MW (182,500 lb/hr) spreader stoker the particulate reduction was ten percent.

Tests on a 26 MW (90,000 lb/hr) Vibra-Grate Stoker showed at full load that the particulate loading was nearly independent of overfire air. The data at full load are shown in Figure 2.

The effect on nitric oxide (NO) emissions of increasing overfire air varied with the unit being tested. On the 87 MW spreader stoker (300,000 lb/hr) nitric oxide emissions were reduced by an average five percent or 16 ppm when overfire air was increased. However, this reduction may not be statistically significant. On the 26 MW boiler the nitric oxide showed scattered results with changes in overfire air. On the 62 MW spreader stoker (200,000 lb/hr) the nitric oxide concentrations again decreased but were not statistically significant. By contrast, on several occasions nitric oxide concentrations increased with increasing overfire air on the 66 MW (182,500 lb/hr) spreader stoker by twenty percent or 65 ppm. Rationalization of this result will be attempted when more data are available.

Tests such as those described above demonstrate the usefulness of overfire air in controlling emissions and improving boiler efficiency. However, overfire air use has limitations. Extensive use of overfire air adds to the dry gas heat loss thereby reducing boiler efficiency; also, if the total excess air is held constant and the undergrate air is reduced proportional to the increase in overfire air, clinkering on the grate or grate overheating may result. Current efforts are being directed toward defining how much overfire air is optimum and where it can best be utilized in the furnace.

The first step toward this goal is to define quantitatively how much air is actually (in comparison with design estimates) entering the furnace through the overfire air and the pneumatic flyash reinjection lines and relate it to the total combustion air. Air flow measurements were made in the various branches of the overfire air and reinjection air ductwork using a thermocouple and standard pitot tube. The results of one such set of measurements on the 66 MW spreader stoker (182,500 lb/hr) are presented in Figure 3. With this figure the fractional contribution of overfire air and flyash reinjection air to the total combustion air can be determined at any load and excess air. Additional charts were made to represent the air flow from the individual air headers as a function of header pressure so that a complete breakdown of air infiltration to the furnace could be made for each test.

The overfire air was biased in different directions to determine where it was contributing most to improved combustion. On the 66 MW (182,500 lb/hr) spreader stoker, the front and rear rows of overfire air jets had an equal influence on particulate loading whereas increasing air flow through the lower rows of overfire air jets resulted in a particulate loading at the boiler outlet which was twenty percent lower than when the flow through the upper rows was increased.

The investigation into overfire air effectiveness will continue at each site tested. The end results will be translated into design guidelines for new units and operating guidelines for existing units equipped with overfire air systems.

FLYASH REINJECTION

Today, the majority of spreader stoker installations reinject into the furnace a portion of the flyash collected by the mechanical dust collector. Selective type dust collectors are often specified which have the ability to separate out the finest 30% of the collected flyash and allow reinjection of only the larger particles which contain the highest carbon content. Total reinjection from a high draft loss collector has been and is discouraged in the vast majority of cases. The mechanically collected flyash (primarily above ten micron size) contains 50 to 80% combustibles and may represent five percent or more in potential fuel savings. One design criteria to be considered with flyash reinjection is the question of how much of the reinjected ash is re-entrained into the flue gas stream without settling on the grate and burning. It may recirculate several times through the boiler until it is small enough, either by successive heating and cooling, mechanical abrasion, or combustion, to pass through the mechanical collector. This results in increased particulate loading at both the boiler outlet and at the mechanical collector outlet. Consequently, boiler tube erosion very likely increases when flyash is reinjected. The importance of this effect has not been substantiated.

An example of flyash re-entrainment is given in Table 1. In this case, flyash reinjection increased particulate loading at the boiler outlet by 315% and at the mechanical collector outlet by 70%. The increase in collection efficiency at the higher inlet loading is most likely due to a change in particle size distribution resulting from the reinjected and re-entrained ash. Size distribution data are not available at this time.

On the 87 MW (300,000 lb/hr) spreader stoker, flyash reinjected from the mechanical collector hopper increased combustion efficiency by 1.5 to 2.5% and increased particulate loading at the boiler outlet by 22 to 39%. Figure 4 illustrates this increase in particulate loading with reinjection for two test sets at different boiler loads. On the 62 MW (200,000 lb/hr) spreader stoker the particulate loading increased 65% at the boiler outlet and 23% at the mechanical collector outlet. At this time, it is believed that the differences in particulate increase are due more to varying rates of flyash reinjection than to design factors in the reinjection system.

The investigation into the impact of flyash reinjection on pollutant emissions and efficiency of coal burning will continue at future test sites. Computer modeling will be attempted to determine what fraction of the reinjected flyash is being re-entrained, and what fraction of the re-entrained ash is subsequently collected and reinjected. It is a goal of this program that these studies will lead to improved methods of reinjection.

EXCESS AIR

The impact of excess air on boiler efficiency is widely understood. Reducing the excess air reduces the dry gas heat loss. Careful combustion air control is also effective in reducing emissions. On the 87 MW (300,000 lb/hr) spreader stoker, a reduction in the level of excess O_2 from six percent to five percent resulted in particulate loading reductions of five to twenty percent. Boiler efficiency was improved. Combustibles losses were reduced by an average of 0.5% of the energy input. Dry gas losses were reduced by an average of 0.8% of the total energy input. Nitric oxide emissions were reduced an average of 55 ppm.

Nitric oxide trend lines are being determined for each boiler tested. Figure 5 presents the trend lines for the 87 MW (300,000 lb/hr) spreader stoker. It is well documented that nitric oxide concentrations increase with increasing boiler load and excess O_2. In stoker fired boilers the factors affecting fuel nitrogen conversion to nitric oxide and the effects of various design changes on nitric oxide emissions are not well understood. It is anticipated that one of the outcomes of this program will be a better understanding of the formation of nitrogen oxides in stoker fired boilers.

Carbon monoxide (CO) concentrations are being examined because they are a very sensitive indicator of the onset of incomplete or unsatisfactory combustion. In general, carbon monoxide has been found to remain at levels below 400 ppm under normal operating conditions. As the excess air is reduced, a point is reached at which carbon monoxide begins to rise rapidly. This "CO limit" is used to tune boilers for efficient and satisfactory operation and is dependent on boiler load as shown in Figure 6. While studying the 87 MW unit, it was found at 80% of full load CO increased rapidly as the excess oxygen was reduced from 5.5% to 4.5% while at lower loads the limit was encountered at lower excess oxygen levels. Other factors such as uniform fuel and air distribution on and through the grate are important in reducing the "CO or malcombustion limit." Unlike gas and oil fired equipment, the operating point in terms of excess air cannot be set strictly by the smoke or CO limit without taking into consideration grate temperature and clinkering. Because coal properties are more variable than those of gas and oil, generally larger operating margins must be established above the minimum excess air operating point.

COAL PROPERTIES

Three or four coals have been fired at each of the first three test sites. In the 87 MW (300,000 lb/hr) spreader stoker, a three percent ash Wyoming coal produced one-third less particulates at the boiler outlet than an eight percent ash Colorado coal. This is not to imply a direct relationship between coal ash and particulate loading because other coal properties are involved. However, this variable will be carefully studied throughout the test program.

Coal size consist is being measured for each test. The ABMA has published graphs stating recommended coal size consist for various stoker fired equipment. According to this graph the percent coal passing a 1/4" square mesh screen should be in the range of 20 to 50% for spreader stokers. Coal having 60% passing 1/4" (see Figure 7) was successfully fired on the 87 MW (300,000 lb/hr) spreader stoker on a day-to-day basis. Revision of these recommended limits may be one of the outcomes of this program.

In the future, tests will be conducted in which coals will be screened at the site to remove their fines thereby altering the size distribution. The effect of coal fines on particulate emissions and operating problems such as piling in front of the feeders will then be examined.

GRATE AIR VELOCITY

Grate air velocity is a design and operating parameter which has been used to reduce particulate emissions. Certain limitations prevent this parameter from being the total answer to particulate emissions. Among the limitations are increased cost, reduced turndown ratio, and clinkering caused by low grate air velocity. Reductions in grate air velocity usually reduce particulate emissions. The velocity can be reduced by fabricating larger grates, reducing load, reducing excess air, or increasing overfire air while holding total excess air constant.

On the 62 MW (200,000 lb/hr) spreader, all of the test data for particulate loading at the boiler outlet correlated fairly well with grate air velocity as shown in Figure 8. The particulate loading is in mass per unit energy input. While such data is often described as showing particulates as a function of load, the grate air velocity can often be reduced as much as twenty percent either by increased use of overfire air, reduced excess air or by a twenty percent increase in the design of the grate area.

Figure 8 includes data obtained on four different coals, various excess air levels, different loads and changes in flyash reinjection rates. It will be important to compare this figure with similar ones from other boilers.

COLLECTION EFFICIENCY

On the spreaders the multiclones were remarkably efficient. On the Vibra-Grate Stoker the opposite was true. Table II shows the comparisons. The difference is primarily due to the fact that the particle size consist of the particulates leaving the Vibra-Grate Stoker is much smaller. Figure 9 shows a comparison of the particle size of the ash leaving this boiler and one of the spreaders. From the Vibra-Grate Stoker, the particles are much smaller.

In addition, it should be remembered that the particulate loading leaving the Vibra-Grate Stoker boiler is much less and, therefore, with the reduced collection efficiency the emissions are similar.

CONCLUSION

Much has been learned about stoker boiler operation and efficiency in the short time this program has been in operation. Much more will be learned in the coming months. When the final report is written, the knowledge gained will be distributed through the ABMA Stoker Technical Committee to the manufacturers of stoker/boiler equipment, the consulting engineers and the boiler purchasers and operators. Then, when its use makes coal combustion in industrial sized stoker fired boilers financially more competitive with the combustion of fuel oil, and environmentally acceptable, then the program will have been a success.

ACKNOWLEDGMENTS

The authors wish to express their appreciation for the assistance and direction given the program by project monitors, W. T. (Bill) Harvey of the United States Department of Energy (DOE) and R. E. (Bob) Hall of the United States Environmental Protection Agency (EPA). Thanks are due to their agencies, DOE and EPA, for co-funding the program.

We would also like to thank the American Boiler Manufacturers Association (ABMA) staff memebers W. M. (Bill) Marx, Executive Director, W. H. (Bill) Axtman, Assistant Executive Director, and B. C. (Ben) Severs, Project Manager, and the members of their Stoker Technical Committee chaired by W. B. (Willard) McBurney of the McBurney Corporation for providing support through their time and travel to manage and review the program. The participating committee members listed alphabetically are as follows:

F. C. Belsak	Island Creek Coal
R. D. Bessette	Island Creek Coal
T. Davis	Combustion Engineering
J. Dragos	Consolidation Coal
T. G. Healey	Peabody Coal
W. B. Hoffmann	Hoffmann Combustion Engineering
N. H. Johnson	Detroit Stoker
K. Luuri	Riley Stoker
J. Mullan	National Coal Association
E. A. Nelson	Zurn Industries
E. Poitrass	The McBurney Corporation
P. E. Ralston	Babcock and Wilcox
D. C. Reschley	Detroit Stoker
R. A. Santos	Zurn Industries
W. Sisken	U.S. Department of Energy

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Finally, our gratitude goes to the host boiler facilities who invited us to test their boilers. At their request, these facilities will remain anonymous to protect their own interests. Without their cooperation and assistance this program would not have been possible.

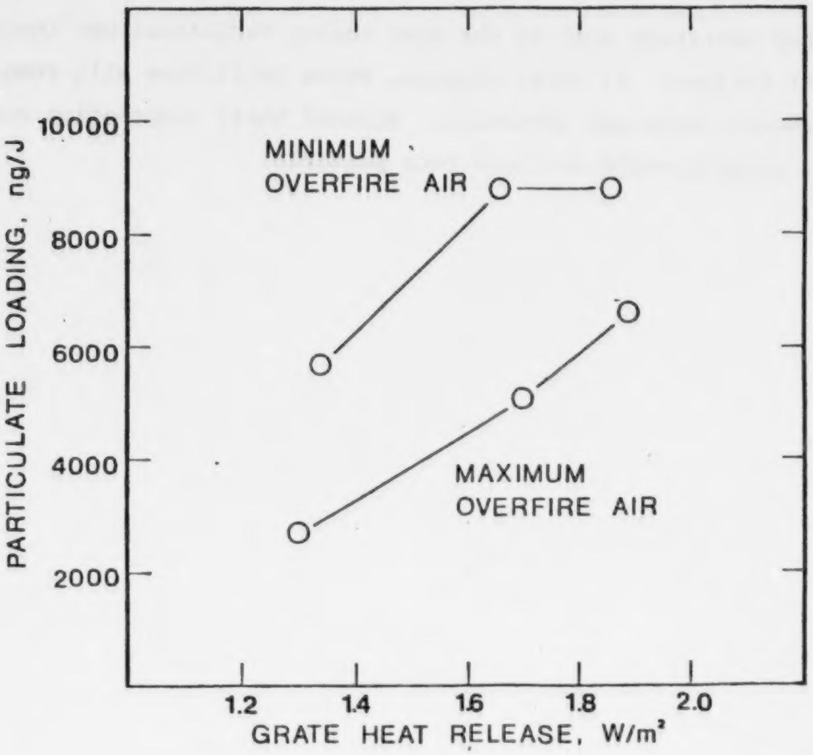
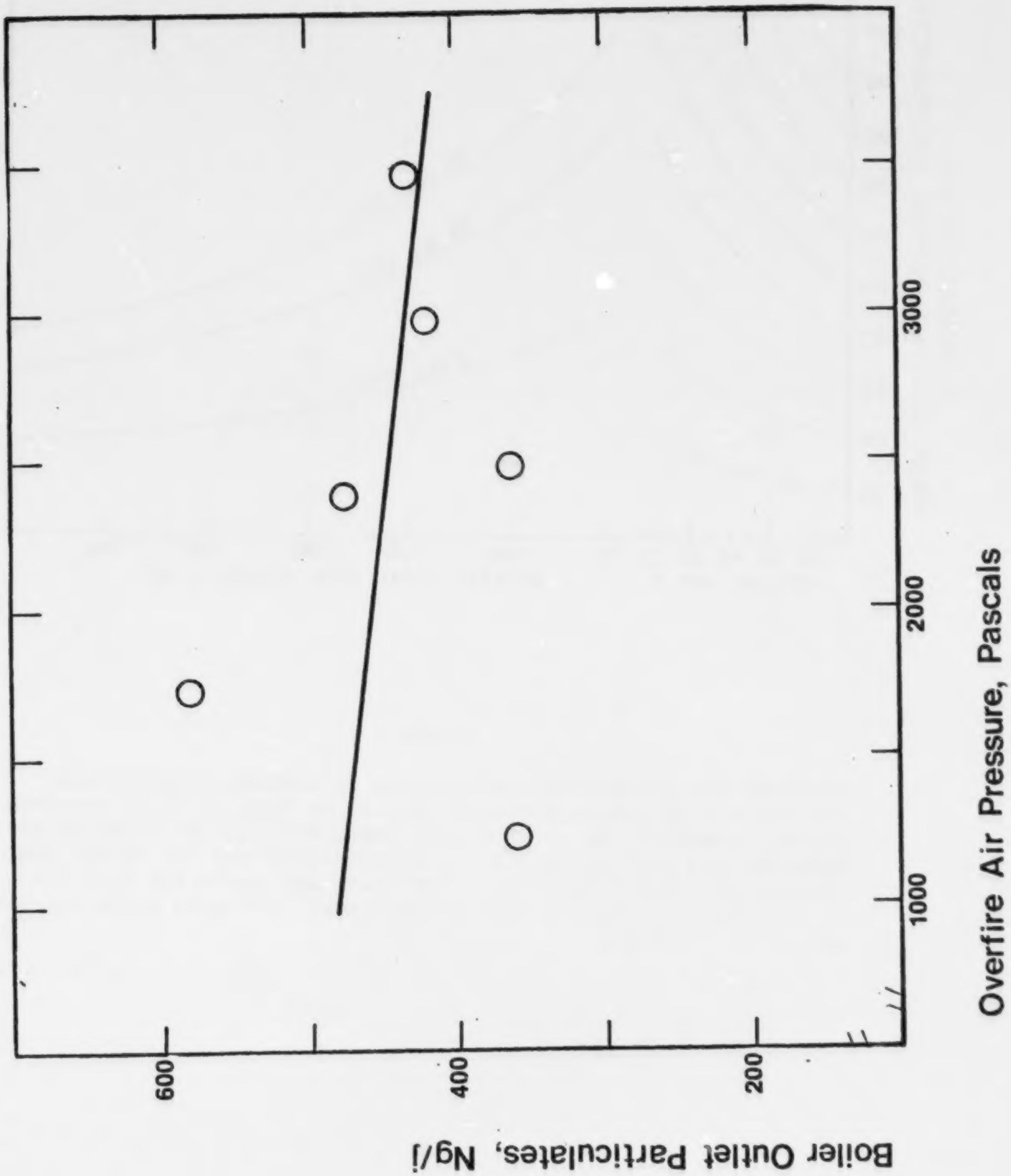


FIGURE 1

PARTICULATE LOADING VS OVERFIRE AIR ON AN 87 MW (300,000 LB/HR) SPREADER STOKER AT CONSTANT EXCESS AIR

FIGURE 2

PARTICULATE LOADING VS OVERFIRE AIR PRESSURE
FOR A VIBRA-GRATE STOKER



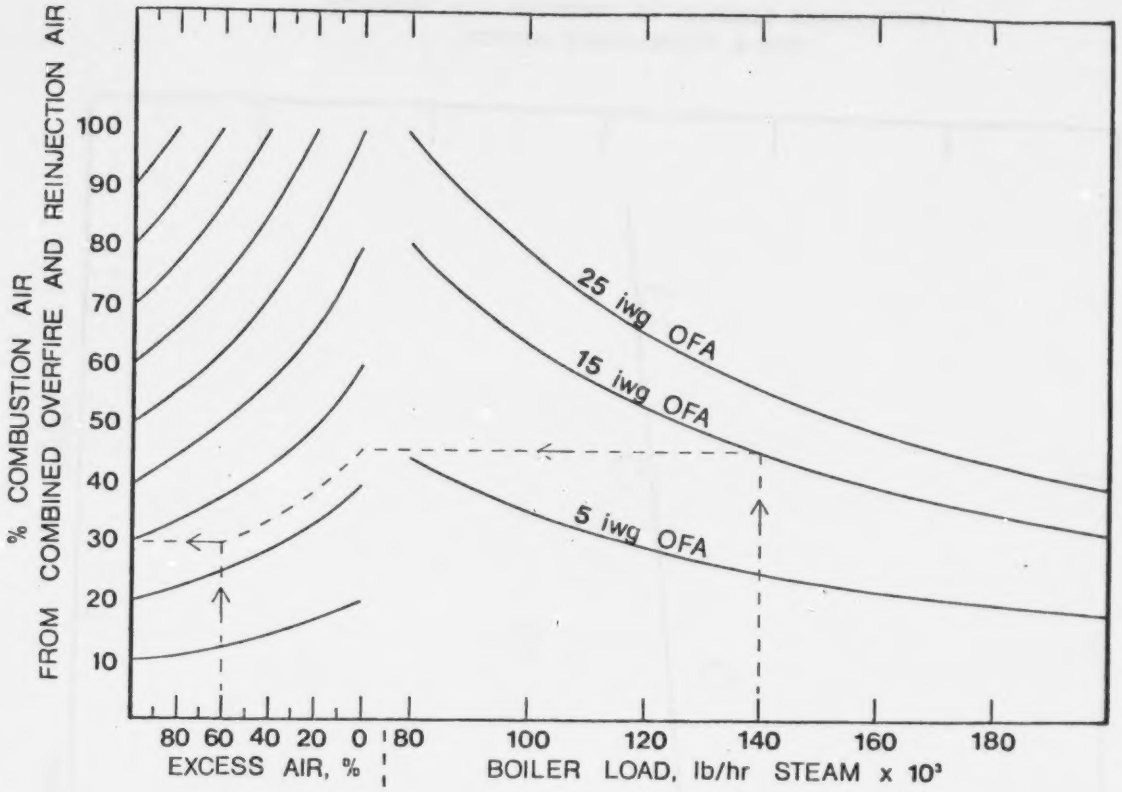


FIGURE 3

NOMOGRAPH FOR DETERMINING CONTRIBUTION OF COMBINED OVERFIRE AIR AND REINJECTION AIR TO TOTAL AIR ON A 66 MW (182,500 LB/HR SPREADER STOKER. EXAMPLE: AT 140,000 LB/HR STEAM FLOW, 15 IWG OVERFIRE AIR PRESSURE, AND 60% EXCESS AIR, IT IS DETERMINED THAT 30% OF THE COMBUSTION AIR IS INTRODUCED ABOVE THE GRATE AND CONVERSELY THAT 70% OF THE AIR IS INTRODUCED THROUGH THE GRATE. (10^3 LB/HR STEAM = 0.364 MW; 1 IWG = 249 PA)

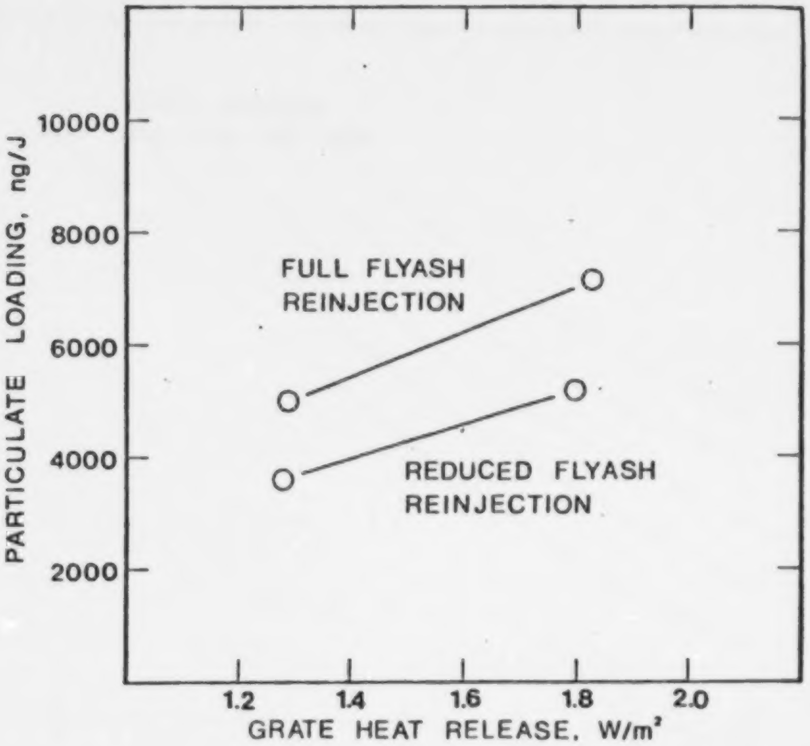


FIGURE 4

PARTICULATE LOADING VS FLYASH REINJECTION ON AN 87 MW (300,000 LB/HR) SPREADER STOKER

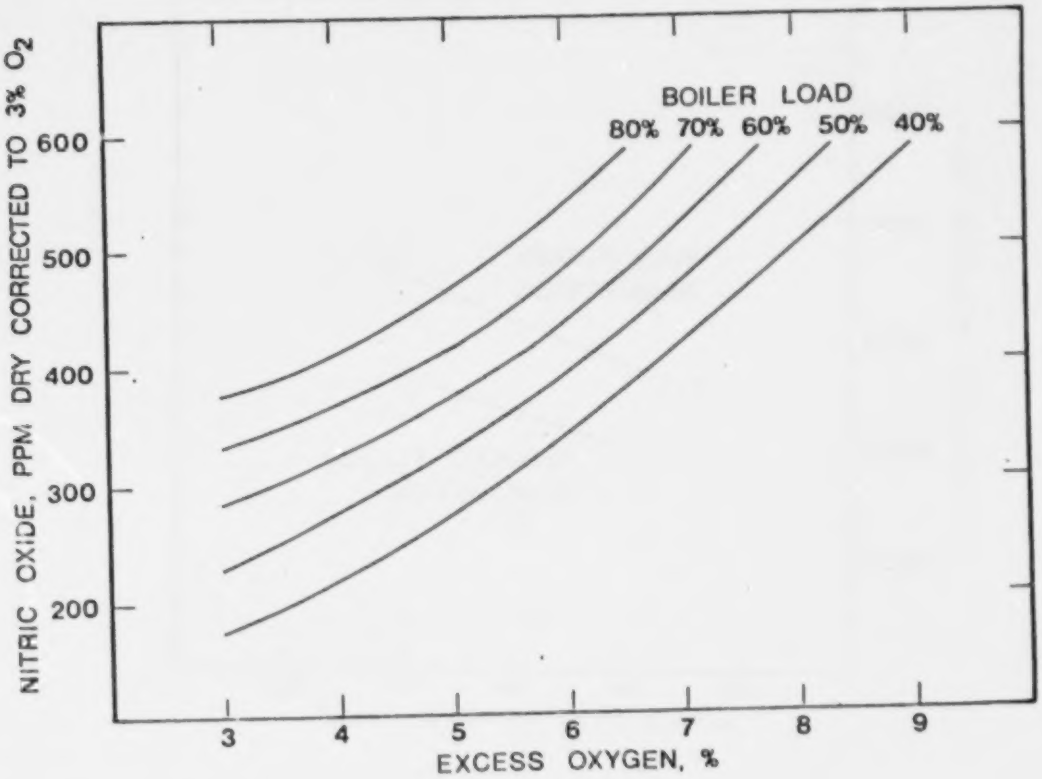


FIGURE 5

NITRIC OXIDE (NO) TRENDS VS EXCESS OXYGEN AND BOILER LOAD ON AN 87 MW (300,000 LB/HR) SPREADER STOKER

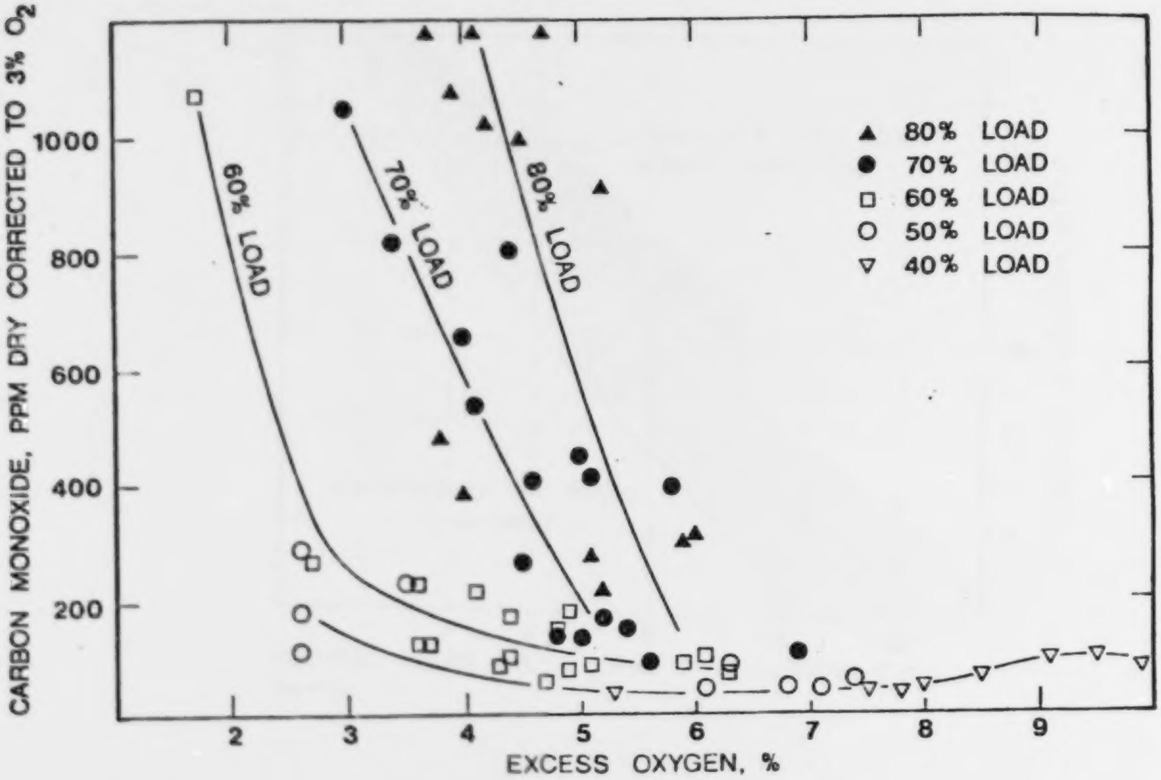


FIGURE 6

CARBON MONOXIDE (CO) VS EXCESS OXYGEN AND BOILER LOAD ON AN 87 MW (300,000 LB/HR) SPREADER STOKER: A COMPOSITE OF 62 DATA POINTS GATHERED OVER A THREE-MONTH TEST PERIOD UNDER VARYING CONDITIONS.

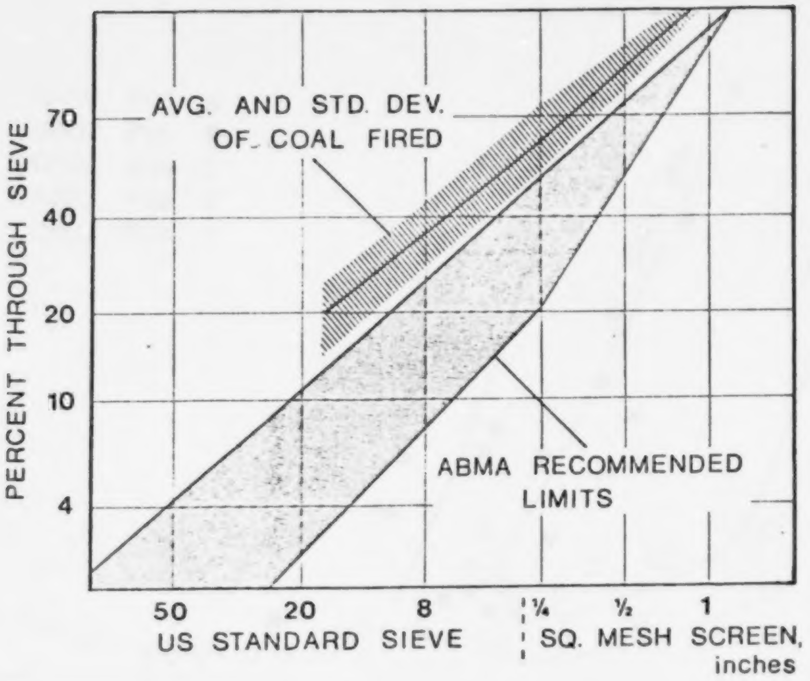


FIGURE 7

AVERAGE AND STANDARD DEVIATION OF SIX COAL SIEVE ANALYSES VS ABMA RECOMMENDED LIMITS FOR SPREADER STOKERS. THIS COAL WAS SUCCESSFULLY FIRED ON A DAY TO DAY BASIS ON AN 87 MW (300,000 LB/HR) SPREADER STOKER (1 inch = 2.54 CM)

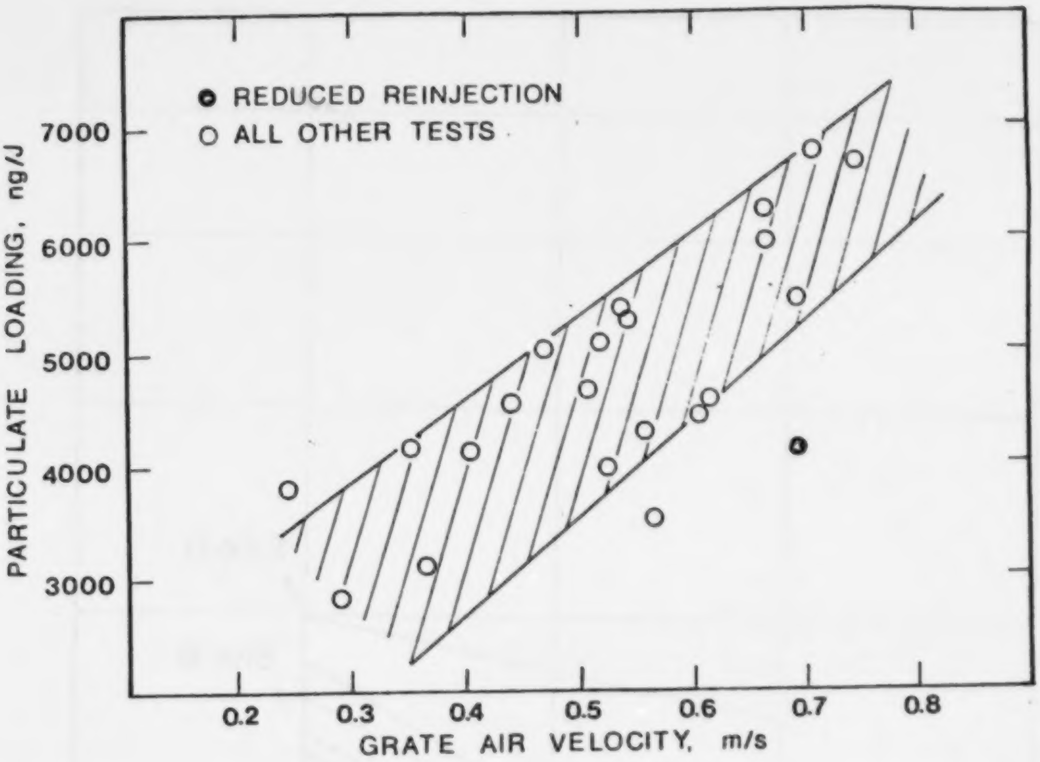


FIGURE 8

RELATIONSHIP BETWEEN GRATE AIR VELOCITY AND PARTICULATE LOADING ON A 62 MW (200,000 LB/HR) SPREADER STOKER

FIGURE 9

PARTICULATE SIZING FOR A SPREADER STOKER (SITE B)
AND A VIBRA-GRATE STOKER (SITE D)

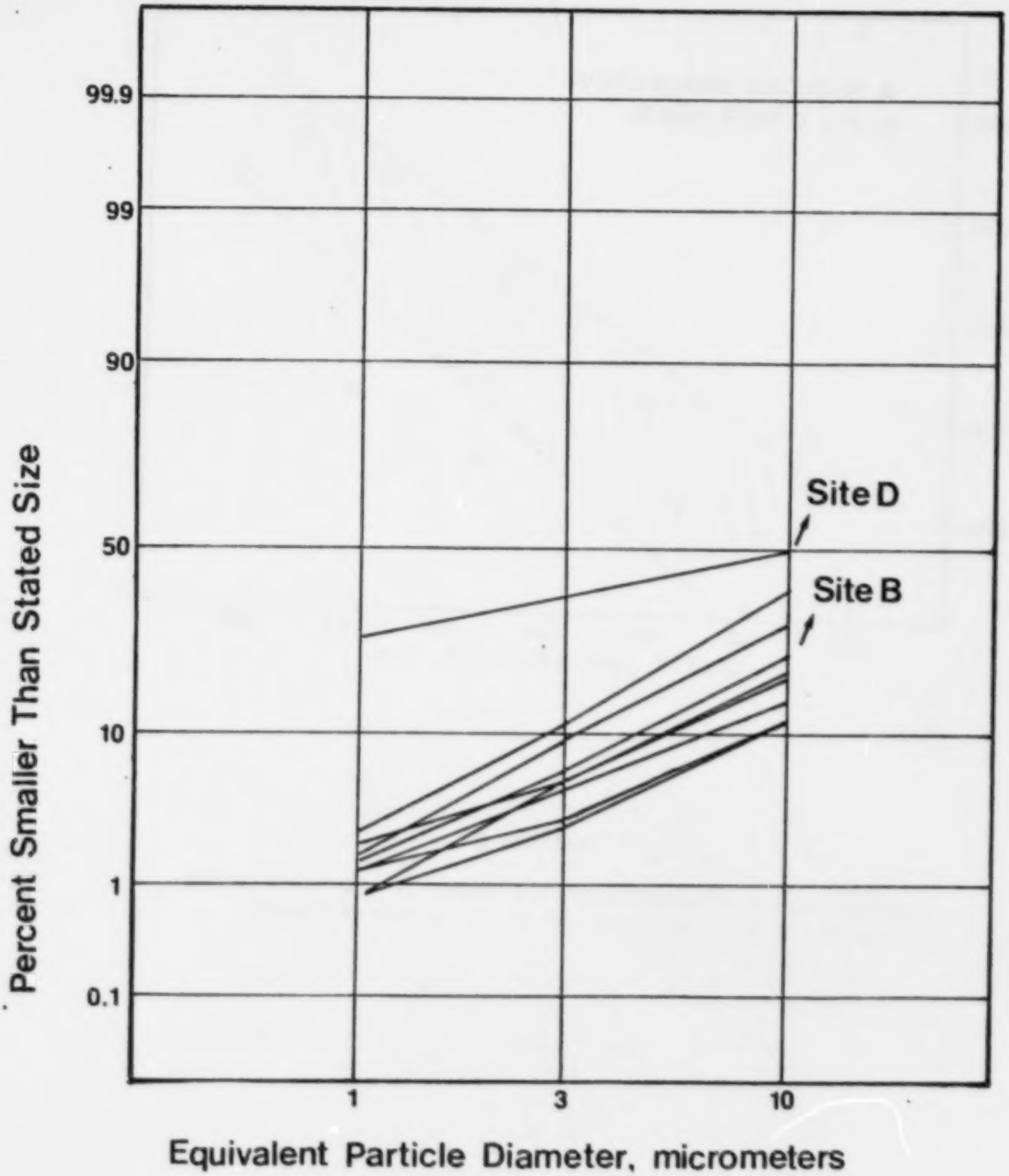


TABLE I

EFFECT OF FLYASH REINJECTION ON PARTICULATE LOADING ON A 66 MW (182,500 LB/HR) SPREADER STOKER AT MAXIMUM LOAD

FLYASH REINJECTION	PARTICULATE LOADING, NG/J ($LB/10^6BTU$) BOILER OUTLET	MECHANICAL OUTLET	MECHANICAL COLLECTOR EFFICIENCY PERCENT
None	2590 (6.0)	207 (0.48)	92.0
Boiler Hopper Only	3010 (7.0)	213 (0.50)	92.9
Boiler Hopper and Mechanical Collector Hopper	10750 (25.0)	350 (0.81)	96.7

TABLE II

MECHANICAL COLLECTION EFFICIENCY

BOILER	TYPE	COLLECTION EFFICIENCIES PERCENT
87 MW	Spreader	70-94
62 MW	Spreader	93-97
66 MW	Spreader	92-97
26 MW	Vibra-Grate	25-75

GUIDELINES FOR ADJUSTMENT OF RESIDENTIAL GAS BURNERS FOR LOW EMISSIONS AND GOOD EFFICIENCY

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GUIDELINES FOR ADJUSTMENT OF RESIDENTIAL GAS BURNERS FOR LOW EMISSIONS AND GOOD EFFICIENCY

ABSTRACT

This paper reviews the basis for development of Guidelines for the adjustment of residential gas burners to minimize air pollution and to achieve efficient use of fuel. The Guidelines were developed jointly by Battelle-Columbus and the American Gas Association Laboratories under contract with the U. S. Environmental Protection Agency. They are intended for use by service managers in training of technicians and by skilled service technicians in maintenance and adjustment of gas burners used in residential furnaces, boilers, and water heaters.

Emission characteristics of typical gas-fired equipment are presented in the paper, and the Guidelines are summarized. Fourteen steps in the recommended adjustment procedure are outlined with condensed descriptions. They comprise preparation steps, adjustment steps, combustion diagnosis steps, and final checks.

The Guidelines include input and reviewer comments from representatives of the gas-heating industry, especially from committees of the American Gas Association and the Gas Appliance Manufacturers Association. The document is scheduled for distribution by EPA early in 1979 and is expected to be reprinted for distribution by the gas industry.

GUIDELINES FOR ADJUSTMENT OF RESIDENTIAL GAS BURNERS FOR LOW EMISSIONS AND GOOD EFFICIENCY

INTRODUCTION

Air pollutant emissions from gas-fired residential heating equipment are usually relatively low, compared to equipment firing other fuels. Nonetheless, proper burner adjustment will contribute to maintaining low emissions plus safe and efficient operation. Adjustment Guidelines for atmospheric gas burners have been developed by the authors for distribution by the U. S. Environmental Protection Agency* as "Guidelines for Adjustment of Atmospheric Gas Burners for Residential and Commercial Space Heating and Water Heating" (Reference 1). This paper is intended to provide an overview of these Guidelines and the basis for their development.

The Guidelines were prepared for use by service managers in training of technicians and by skilled technicians in gas burner servicing. By following the step-by-step procedure outlined in the Guidelines, the skilled gas-burner service technician will be able to adjust residential and commercial heating equipment and water heaters to minimize air pollution, attain optimum efficiency, and provide safe operation.

Similar Guidelines for oil burners were published by EPA (References 2 and 3) and their development was described in APCA papers (References 4 and 5). Air-pollution control agencies may wish to promote the use of the Guidelines in this series as a means of updating good practice by burner servicing organizations to achieve both low emissions and efficient operation.

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* EPA Contract No. 68-02-2653. Project Officer, R. E. Hall.

TYPICAL EMISSION LEVELS

While burner design has an effect on the emission of NO_x or CO, the appliance to which the burner is applied is also important. Forced-air furnaces, water heaters, space heaters and boilers all have different heat transfer rates, combustion intensities, recirculation patterns, and flame aerations. Each of these factors can influence the formation of NO_x as much as burner design parameters.

Emissions for Various Gas Appliances

Table I presents emissions measured by the A.G.A. Laboratories (References 6, 7, and 8) for several types of gas heating appliances operating in the laboratory. These data were obtained for units operating with well-adjusted flames after an equilibrium operating condition was achieved. All samples were taken downstream from the draft hood, because that point is representative of what actually is emitted into the atmosphere. (Note: For determining combustion and appliance efficiency of a field-installed unit, the recommended sampling point for measuring CO_2, CO, and temperature is before the draft hood.)

All values of NO, NO_2 and CO presented in Table I are on an air-free basis, based on an ultimate CO_2 of the natural gas fuel used of 12.0 percent. An air-free basis, or an emission factor basis (pounds per million Btu of natural gas burned) is necessary in order to make comparisons. To obtain the actual sample concentration in the flue gases emitted to the atmosphere, the air-free concentration is divided by the ratio of the ultimate CO_2/sample CO_2.

These data on emissions are for conventional gas burning equipment with typical burner adjustments and are in general agreement with those reported by others (References 9 and 10). The data are also representative of emissions from current burner designs; however, R&D efforts have shown that lower NO_x emissions are feasible with some burner designs.

Effects of Burner Adjustment

Table II presents average emissions for 38 forced-air furnaces equipped with atmospheric-injection burners. The overall average is subdivided into averages for single-port burners and for multiport burners. In all cases, the yellow-flame condition (which represents a misadjusted flame) showed higher CO and aliphatic aldehyde levels when compared to the well-adjusted blue-flame condition. With the yellow-flame condition, average emissions of NO were lower, but NO_2 emissions were higher; the combined result, expressed as NO_x, averaged slightly lower for the yellow-flame condition.

Tables I and II also show that NO_x levels for single-port burners were slightly less than for multiport burners. This small difference is statistically significant, but may not be practically significant. We believe the difference is due to the following:

- Multiport burners provide more sites for near-stoichiometric flame fronts, with attendant maximum flame temperatures which cause higher NO_x production,
- Single-port burners generally have larger flame volumes with less regions of high intensity which lowers the potential for optimum NO_x production, and
- The longer flames of single-port burners allow more time for NO_x decay.

TYPICAL CHARACTERISTICS OF NATURAL GAS-FIRED BURNERS IN HEATING APPLIANCES

Figure 1 shows flame regions of stable blue flames and yellow-tip flames controlled by gas input rate and primary air adjustment for typical atmospheric gas burners; the region of undesirable yellow flames occurs at high input rates and low primary-air aeration. (Note in Table II that emissions of CO and aldehyde were increased when operating burners in the yellow-flame combustion region.)

Figure 2 illustrates the effects of combustion air on CO and CO_2 concentrations for typical atmospheric gas burner installations. It demonstrates that the CO is very low at the proper CO_2 adjustment region. The figure also shows that the CO_2 reading does not always predict the CO level. With a deficiency of combustion air, it is still possible to obtain a high CO_2 level, but with an undesirable CO level. Therefore, CO_2 level alone cannot predict the CO concentration. For this reason, it is necessary to measure the CO concentration to be certain it is at an acceptable level.

It should be recognized that gas burners, as applied to matched furnace-burner or boiler-burner units, do not have as wide a range of air adjustment available to the service technician as do residential oil burners. The primary air setting adjustment has a realtively narrow range of adjustment, and the design of the appliance mainly determines the secondary air supply. For conversion burners, the service technician usually has more range of adjustment (Reference 11).

Figure 3 demonstrates the expected effect of excess air on CO, NO_x, and hydrocarbon (HC) emission of a gas burner installation by showing the relationship of these emissions to excess air supply (or CO_2 value). This figure shows the normal operating excess-air region for natural and LP gas appliances in terms of excess air.

CO emission levels are at unacceptable levels under a deficiency of combustion air. HC emissions also are high with a deficiency of combustion air and may increase under very high excess-air conditions because of lifting flames. The NO_x ($NO + NO_2$) emission reaches a peak very near a stoichiometric air-gas mixture (zero percent excess air) because the maximum flame temperature occurs at this condition.

Figure 3 shows that it is desirable to operate under an excess air condition of from about 40 to 90 percent in order to minimize the pollutant emission levels and maintain good efficiency. Most atmospheric gas furnaces will perform as shown. For some burners, the normal region will be wider or narrower; a few burners will operate satisfactorily outside the region shown. The general trend of the pollutant emission, however, will be similar to that shown by the figure.

The service technician should visualize the interaction of emissions and burner adjustment to develop an appreciation that the relationship between CO and CO_2 is basic to setting a burner for minimum emissions by use of field measurements. Note that evaluation by using only CO_2 measurements could result in high CO and HC. This can be avoided by measuring both the CO_2 and CO levels. The heating industry has traditionally used CO_2 readings as the basis for burner adjustment, mainly because of the availability of effective field-type instruments. However, O_2 measurements offer the advantage of positively identifying whether operation is in the fuel-rich or fuel-lean region. While instruments for field measurement of O_2 are being introduced (Reference 12), and may ultimately gain acceptance, the Guidelines that follow are based on CO_2 and CO measurements.

RECOMMENDED ADJUSTMENT PROCEDURES

Important criteria in making gas burner adjustments are:

- To provide safe and reliable operation,
- To provide efficient fuel utilization, and
- To minimize emissions of air pollutants.

The Guidelines summarized below are intended for adjustment of atmospheric-type gas burners for residential and commercial space heating and for water heating systems. The procedures are supplemental to manufacturers' installation instructions, the National Fuel Gas Code (Reference 13), other installation codes or other handbooks (Reference 14), and apply to burners fired with either Natural Gas or Liquified Petroleum (LP) gases.

The adjustment procedures apply to atmospheric-type gas burners of the single-port and multiported types such as ribbon, slotted-port and drilled-port as used in manufacturer-designed burner/furnace units, burner/boiler units, or complete water-heater units. Although the principles apply to conversion-type gas burners, these burners require special adjustment procedures, and the burner manufacturer's instructions should be followed.

The following steps are emphasized in the Guidelines from the viewpoint of minimizing air-pollutant emissions, plus maintaining good efficiency and safe operation. A total of fourteen steps are outlined in four different categories: preparation steps, combustion adjustment steps, combustion diagnosis steps, and final checks. A condensed summary follows.

PREPARATION STEPS

1. Clean Burner and Pilot

   The most common malfunction of main burners and pilots is caused by excess dirt, lint, or other debris. Blockage of primary-air openings causes the burner to operate with incomplete combustion and can lead to soot and excess CO formation. Remove burners and clean the burners, burner ports, burner and pilot orifices and primary air openings. Make preliminary adjustment of the primary air shutters, if any, by following step 6.

2. Adjust Manifold Pressure

   Adjust pressure regulators to deliver gas to burners at the proper pressure. If the appliance rating plate specifies a manifold pressure, adjust to that pressure; if not specified, set pressure as follows:

   Natural Gas: 3.5 inches water column
   (Appliances with regulators)

   LP Gases: 11 inches water column
   (Regulator may be at tank)

3. Adjust Pilot

   The pilot flame should be soft blue in color. Propane pilots may have slightly yellow tips. The flames should surround the tip of the thermocouple or flame sensor and, if there is a separate ignition port, flame should reach the main burners. A pilot adjusting screw is usually located on the main gas valve or pilot shutoff valve.

4. Adjust Main Burner Input

   After the unit has been operating at least 10 minutes, check the gas input rate by timing one revolution of the gas meter test dial, making sure that all other gas-burning appliances are not operating. Note the number of seconds for one full revolution, and calculate input as follows:

$$\text{Input, Btu/hr} = \frac{\text{cubic ft per rev}}{\text{seconds per rev}} \times 3600 \times \text{HV}$$

where HV = gross heating value of gas, Btu/cubic foot.

Adjust the input to within ±5 percent of the value noted on the rating plage by adjusting the pressure regulator or by changing burner orifice.

5. Check Ignition — Allow the burner to cool and check operation of ignition system by cycling several times while the burner is cold to ensure prompt ignition on cold start. Then operate the burner at least 10 minutes, or until thoroughly hot, and repeat several ignition cycle checks to ensure prompt ignition on hot start after about 5 seconds OFF time.

COMBUSTION ADJUSTMENT STEPS

6. Adjust Burner — To adjust primary air, allow at least 10 minutes for the burners to heat up, close primary air shutter until yellow tips appear, then open air shutter until all yellow completely disappears. The flame should be a clear blue color. Too much primary air causes noisy, hard flames which could result in flame lifting, flashback and emission of unburned hydrocarbons. Too little primary air causes yellow flames which could produce high CO and soot emissions. (See Figure 1)

Secondary air is controlled by the burner and appliance design and should not need modification. However, conversion burners may need secondary-air adjustment and the manufacturer's instructions should be followed. (Reference 11)

7. Sampling — Flue gas samples for analysis should be taken from inside the appliance approximately 1 inch upstream of the draft hood inlet. CO_2 and CO are usually measured with instruments using color-sensitive indicators. If several flue outlets are provided, individual samples should be taken from each, or a partial sample taken from each outlet to make up the full sample.

8. Check CO_2 — If it is desired to assess the burner adjustment in terms of the best practical efficiency, follow this procedure. After the burner has been in operation for at least 10 minutes, measure and record the CO_2 in the flue outlet (following the instructions provided by the CO_2 instrument manufacturer).

For safe and most efficient operation, the CO_2 concentration should be near 8.5 percent for Natural gas and

10.0 percent for LP gases. See Figures 2 and 3 for typical operating regions.

9. Check CO

This step is important for safety, whether or not step 8 is followed. After the burner has been in operation for at least 10 minutes, make a CO measurement (following the CO instrument manufacturer's instructions).

Typical CO values for properly adjusted appliances, operating at rated input, range from 25 to 100 ppm (0.0025 to 0.010 percent); however, values as high as 300 ppm may be encountered in the flue sample, since this is equivalent to the maximum allowable value of 400 ppm (air-free) at a CO_2 of 8.5 percent as allowed by the ANSI standards (References 11, 13, and 14).

COMBUSTION DIAGNOSIS

10. Check Performance

A well-adjusted gas burner should be capable of operating with a CO level not greater than 100 ppm in the flue gases with a CO_2 level between 6.0 and 8.5 percent for Natural gas and 7.0 to 10.0 percent for LP gases. If these values cannot be reached, check the following:

a. Too low a CO_2 level could mean circulating air leakage into the combustion air, due to a faulty seal around the secondary air opening of the unit.

   Too low a CO_2 level could be caused by a defect in the furnace heat exchanger. If the CO_2 levels obtained with and without the blower operating differ by more than 0.4 percent, a check of the combustion chamber and heat exchanger should be made.

b. If the CO_2 and/or CO are too high, this could mean an improper combustion air supply. Spillage from the appliance draft hood due to negative pressure in the room also indicates inadequate air supply. Spillage will also result from a blocked chimney or vent. If inadequate air supply is suspected, refer to Section 1.3.4 of the National Fuel Gas Code (Reference 13) or comparable provisions in local codes for specific detailed recommendations for providing air for combustion and ventilation.

11. Efficiency Checks

To determine the steady-state efficiency, follow this step. Measure the flue-gas temperature after at least 10 minutes of operation at the same point that the CO_2 sample was taken. Determine the net flue-gas temperature by subtracting room temperature from the flue-gas temperature reading.

Using this net temperature value and the percent of CO_2, determine the appliance flue loss from Figure 4. The appliance thermal efficiency is equal to (100 - flue loss). Use the values shown in Table III to determine whether the unit is operating at a satisfactory efficient level. Note that this gives steady-state efficiency. Seasonal efficiency will be less, due to flue losses occuring during OFF cycles. These losses are minimized by avoiding overfiring that occurs when gas input rate exceeds that needed to satisfy the actual steady-state heat losses.

FINAL CHECKS

12.	Ignition	Check operation over several repeated cycles at about 5-second intervals, to ensure prompt ignition.
13.	Controls	Check setting of all operating and limit controls before leaving installation. For modern forced-warm-air systems, usual good practice is to set the fan control at 115 to 125 F ON and 90 to 100 F OFF for practical performance and good efficiency.
14.	Regular Cleanup	Annual burner checkup is recommended, with cleaning as necessary.

* * * * *

Experienced service technicians will observe that these procedures are essentially the same as they have followed in normal good practice. Adjustment of gas burners by these procedures will help to provide safe and reliable operation, to minimize emissions, and to provide efficient fuel utilization.

ACKNOWLEDGMENTS

Significant inputs to the development of these Guidelines were made by a number of reviewers from the gas industry, the equipment servicing industry, and others. Special acknowledgment is made to reviewers representing the following:

American Gas Association (A.G.A.)

- by members of the A.G.A. Customer Service and Utilization Committee

Gas Appliance Manufacturers Association (G.A.M.A.)

- by members of the Joint A.G.A./G.A.M.A. Customer Service Task Group

Air Pollution Control Association (APCA)

- by members of the APCA Residential Fuel Combustion Committee.

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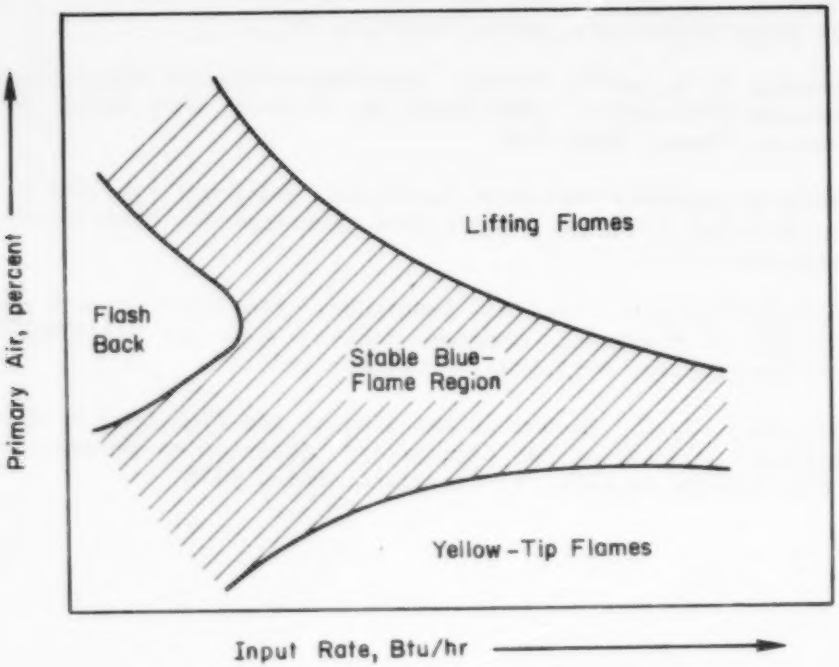

Primary Air, percent
Input Rate, Btu/hr
Lifting Flames
Flash Back
Stable Blue-Flame Region
Yellow-Tip Flames

Figure 1. Typical characteristics of atmospheric gas burners -- limits of lifting, yellow tipping and flashback.

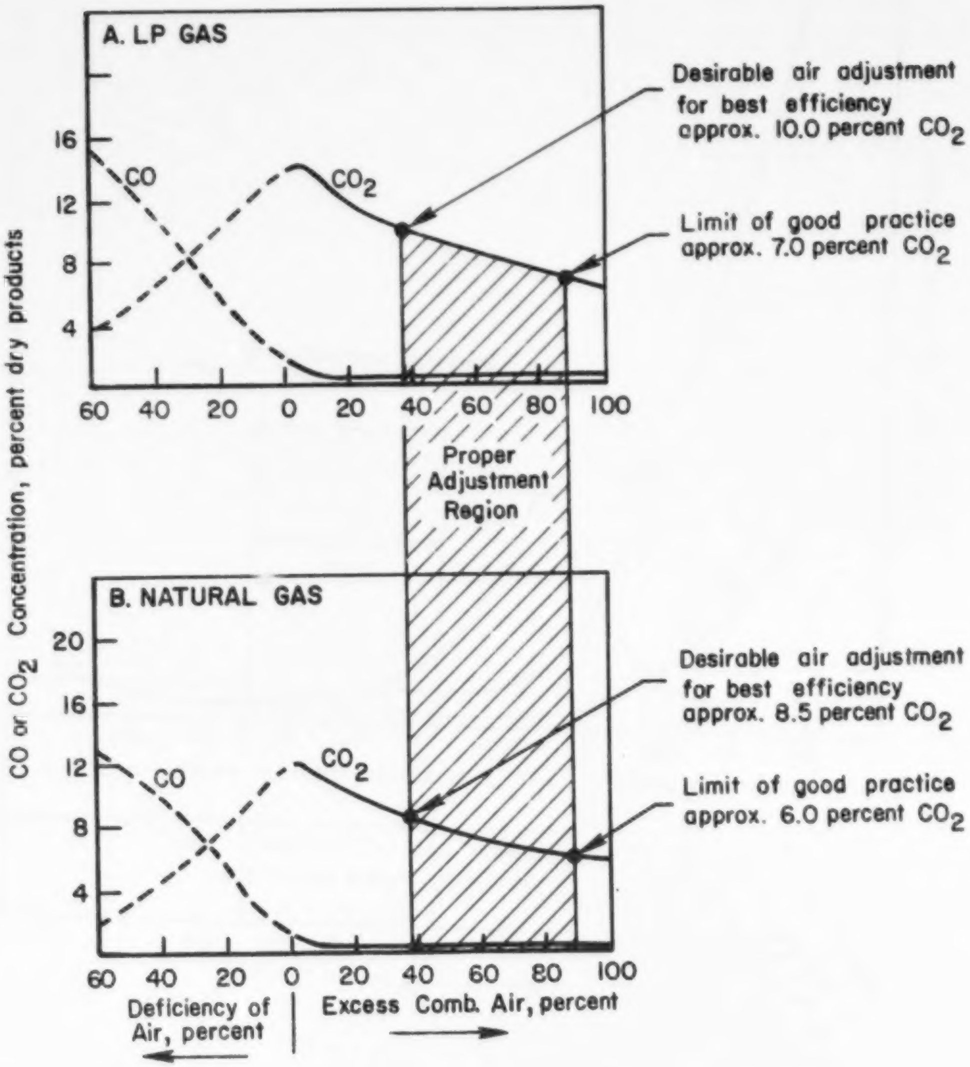


Figure 2. Effect of fuel/air ratio on CO and CO_2 concentration for a typical natural gas and LP gas burner showing proper adjustment region.

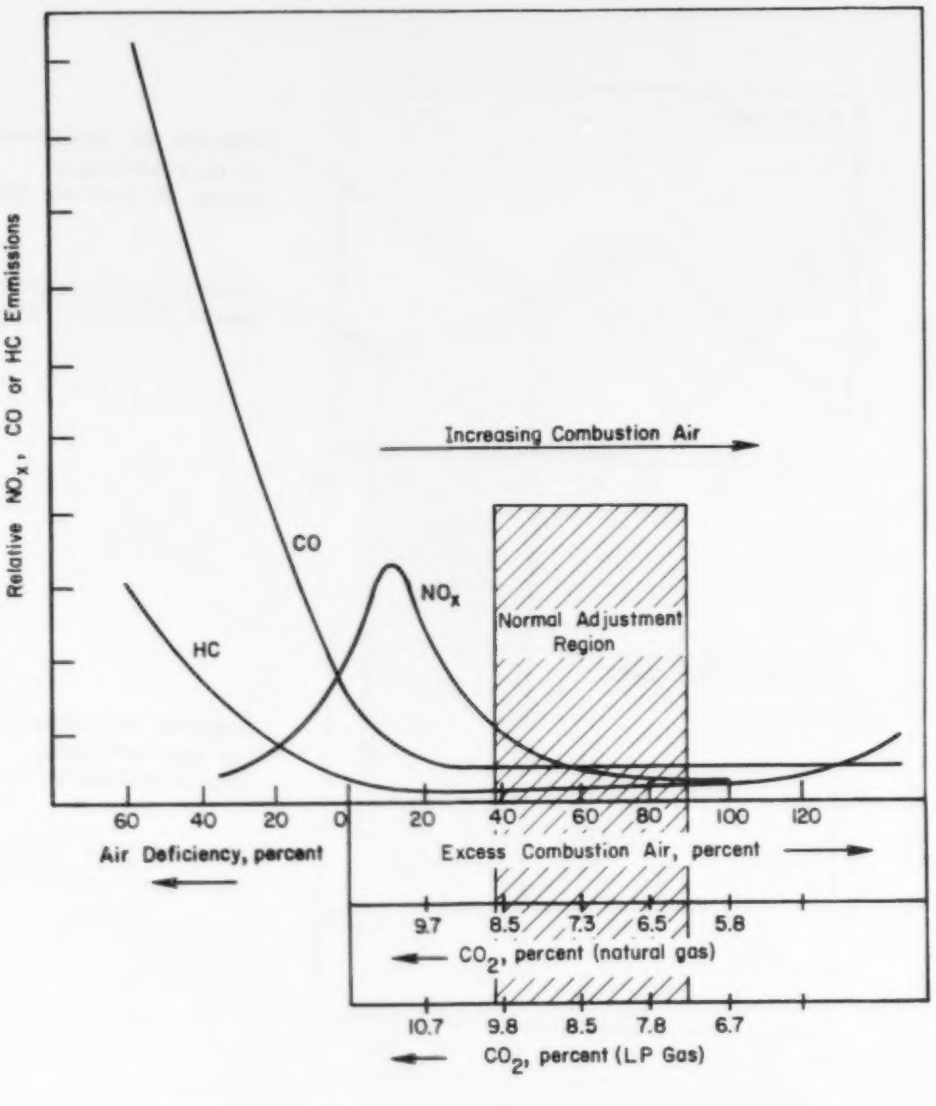
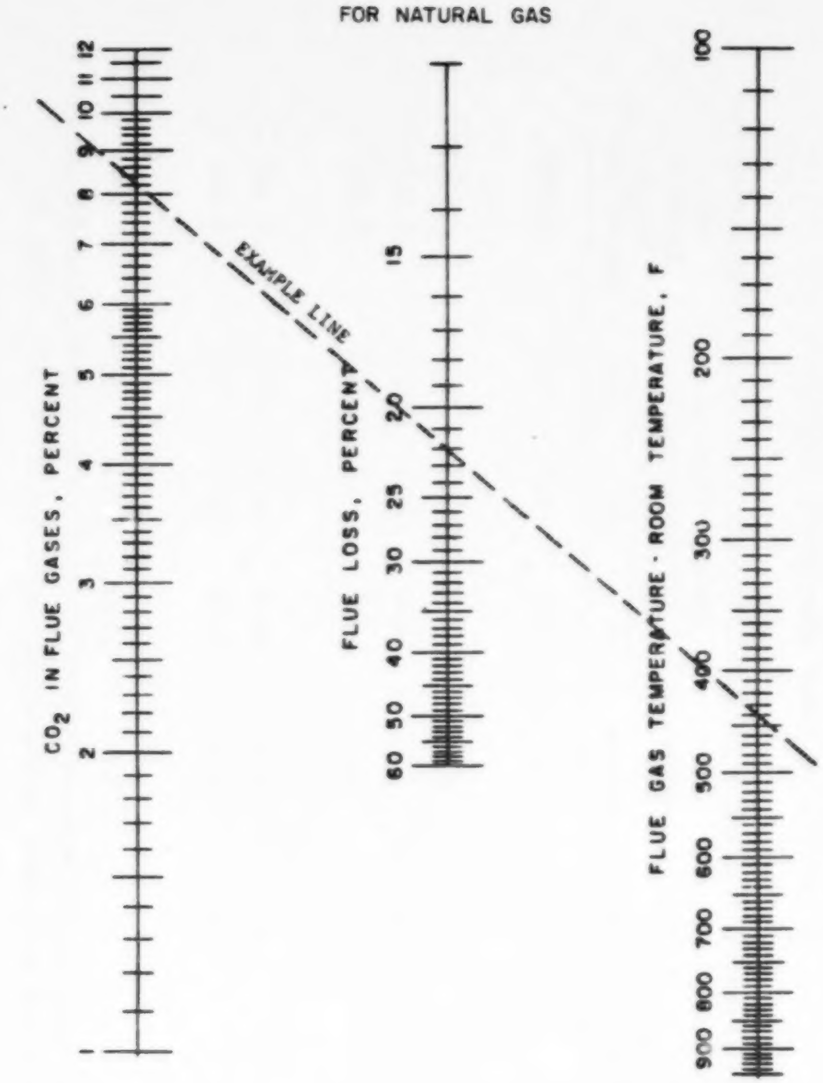


Figure 3. Effect of air adjustment on gaseous emissions for a typical atmospheric gas burner



Example: **8.2 percent** CO_2 **22 percent flue loss (78 percent efficiency)** **440 F net**

Figure 4. Nomograph for determining flue loss and steady-state efficiency from CO_2 and flue-gas temperature for natural gas firing (Reference 15).

Limited to use with natural gas as follows:

Heating value, gross:	970 - 1100 Btu/standard cubic foot
Specific gravity:	0.57 - 0.70
Ultimate CO_2:	11.7 - 12.2 percent

TABLE I. EMISSIONS FROM TYPICAL HEATING APPLIANCES WITH NATURAL-GAS FIRED ATMOSPHERIC BURNERS(a)

Appliance and Burner Type	Number of Units	Sample CO_2, Percent	Average Flue Gas Concentration, (Air Free) PPM			NO_x Emission Factor, $lbs/10^6$ Btu(b)
			CO	NO	NO_2	
Forced Air Furnaces	38	5.8	8.1	88.8	4.7	0.098
Water Heater						
Domestic	17	5.4	7.0	110.1	4.8	0.120
Commercial, Multiport	3	5.4	6.6	179.6	5.3	0.194
Commercial, Single Port	1	5.1	3.8	74.1	3.7	0.084
Hot Water Boilers						
Multiport	11	4.3	61.0	146.6	12.0	0.168
Single Port	3	3.4	11.0	89.4	6.9	0.102
Steam Boilers						
Multiport	4	4.6	69.0	143.9	10.9	0.161

(a) Sampled downstream of the draft hood during steady-state operation with 5 feet of vertical stack

(b) Sum of the NO and NO_2 calculated as NO_2

TABLE II. EFFECT OF BURNER ADJUSTMENT MADE ON AVERAGE EMISSIONS FROM NATURAL-GAS-FIRED FORCED-AIR FURNACES(a)

Average	Flame(b)	Sample CO_2, Percent	Average Flue Gas Concentration, ppm, Air Free				NO_x Emission Factor, lbs/10^6 Btu(d)
			CO	NO	NO_2	HCHO(c)	
Overall	Blue	5.8 ±1.0	8.1 ±2.6	88.8 ±14.0	4.7 ±2.4	0.18 ±0.14	0.098 ±0.015
	Yellow	6.0 ±1.0	208.0 ±4.0	73.6 ±16.0	9.7 ±3.9	0.60 ±0.39	0.088 ±0.014
Multiport Burner	Blue	5.9 ±0.9	8.2 ±2.8	94.0 ±11.7	4.8 ±2.5	0.20 ±0.14	0.104 ±0.012
	Yellow	6.0 ±0.9	201.0 ±3.0	80.0 ±10.0	8.8 ±2.6	0.62 ±0.40	0.093 ±0.010
Single Port Burner	Blue	5.5 ±1.1	7.8 ±2.1	75.0 ± 9.6	4.4 ±2.2	0.14 ±0.15	0.084 ±0.010
	Yellow	5.8 ±1.1	255.0 ±6.0	56.9 ±17.6	12.1 ±5.8	0.60 ±0.40	0.073 ±0.014

(a) Sampled downstream of the draft hood during steady-state operation with 5 feet of vertical stack. The ± value is the standard deviation of the average shown.

(b) Yellow flames are undesirable and result from a misadjusted burner.

(c) Total aliphatic aldehydes expressed as formaldehyde (HCHO).

(d) Sum of NO and NO_2 calculated as NO_2.

TABLE III. TYPICAL STEADY-STATE THERMAL EFFICIENCIES OF CONVENTIONAL GAS-FIRED RESIDENTIAL AND COMMERCIAL HEATING EQUIPMENT

System	Thermal Efficiency, Percent(a)	
	Good Practice	Acceptable
Forced Air Heating(b)	75 or more	72 - 75
Gravity Heating	70 or more	67 - 70
Hot Water or Steam Boiler	75 or more	72 - 75
Domestic or Service Water Heater	72 or more	68 - 72

(a) Overall Thermal Efficiency = 100 - flue loss, percent, where flue loss is expressed as a percent of the gas input (gross heating value) that is lost up the flue in steady-state operation. This assumes that any jacket loss is useful heat.

(b) A field measurement program by four gas utilities showed that the "as found" thermal efficiency of about 200 furnace installations had a mean of 74.5 percent thermal efficiency with a standard deviation of 3.77 percent.

TABLE IV. CONVERSIONS TO SI UNITS

The Guidelines have been prepared using English engineering units, as commonly used in the gas heating industry and as most familiar to the service technician. This provides factors for conversion to SI units, if desired.

Multiply	by	To Obtain SI Units	
Btu	1.056	kilojoules	kJ
cubic feet	2.832×10^{-2}	cubic meters	m^3
Btu/cubic foot	37.26	kilojoules/cubic meter	kJ/m^3
cubic feet/min	4.720×10^{-4}	cubic meters/sec	m^3/sec
degrees F	$\frac{5}{9}(F - 32)$	degrees C	
inches	2.54	centimeters	cm
pounds/million Btu	0.430	grams/Megajoule	g/MJ

FIELD VERIFICATION OF LOW-EMISSION INTEGRATED RESIDENTIAL FURNACES

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ABSTRACT

A prototype low-emission, improved-efficiency, oil-fueled, warm-air residential furnace was previously developed under EPA sponsorship. In laboratory tests, the prototype furnace produced approximately 65% lower emissions of oxides of nitrogen (NO_x), and, at the same time, operated at high thermal efficiency (Reference 1).

Six units of the prototype low-emission furnace were field tested during the 1977-78 winter heating season in homes in the Boston, Massachusetts, and Albany, New York, areas. Their emissions behavior was monitored by making monthly measurements of flue gas composition with a mobile laboratory. Their performance was monitored with a set of continuously recording time, temperature, and flow rate instrumentation.

All six field-tested prototype furnaces functioned satisfactorily throughout the heating season with only a few minor shakedown problems. The emission goals, set very close to what had been achieved in the laboratory, were met. The NO emissions goal was 0.65 g/kg fuel burned — a reduction of 65% from the average of existing furnaces. Emission levels of carbonaceous pollutants — smoke, carbon monoxide, and unburned hydrocarbons — were also acceptably low. None of the furnaces exhibited significant drift of any emission level during the season.

Steady-state thermal efficiencies were approximately 83 to 84%, while cycle-average thermal efficiencies averaged approximately 74%. Fuel consumptions were compared with those of the predecessor furnaces during the 1975-76 and 1976-77 heating seasons by normalizing to a per degree-day basis. All six units consumed significantly less fuel, averaging 18.5% less than the prior two seasons.

The data base is currently being expanded by continuing the field testing for a second full heating season.

ACKNOWLEDGMENTS

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Acknowledged with appreciation are Mr. Clifford Hauenstein, Program Manager at Rockwell International, Messrs. Clark Zeh and Ronald VonRonne of Main-Care Heating Service, Delmar, New York, and Mr. Joseph Iorio, Sr., of Atlantic Heating and Air Conditioning Company, Brookline, Massachusetts, for their cooperation and contributions leading to the successful execution of the 1977-78 field test.

INTRODUCTION

Under a previous EPA contract, design criteria were determined whereby gun-type pressure-atomizing oil burners, such as are commonly used in residential and commercial space-heating systems, may be modified so that they produce substantially lower emissions of oxides of nitrogen (NO_x) and burn smoke free at more efficient operating conditions. Those design criteria were used to modify existing burners of two sizes — a 1.05-ml/s (1.0-gph) residential burner, and a 9.47-ml/s (9.0-gph) commercial burner — and were shown to be valid in laboratory testing (Reference 2).

Further laboratory research with the residential-size, low-emission burner provided additional design criteria for fireboxes matched to the burner to achieve even lower NO_x emissions (Reference 3). Thereafter, proof-of-concept experiments were carried out in the laboratory using a prototype residential warm-air furnace embodying several design modifications (References 4 and 5). The resultant NO_x emissions were reduced to about 35% of the estimated average established by a field survey (Reference 6) of comparable, existing, installed units. Further, the laboratory performance data showed that the prototype furnace's cyclical efficiency should be 10 or more percentage points higher than the estimated average of the existing residential oil furnace population.

The present investigation is a logical continuation from those encouraging laboratory results. Potential benefits of commercializing the derived technology are being demonstrated by conducting field tests of several low-emission furnaces in actual residences. First, however, it was appropriate to effect further refinements of the burner and furnace designs, partially to further optimize emissions and efficiency performance and partially to improve commercial producibility. Thus, the two objectives were: (1) beginning with the prototype furnace tested earlier, to optimize further the design of an integrated, low-emission, high-performance, oil-fueled, residential warm-air furnace, and (2) to verify its pollutant emissions and thermal efficiency performance by operating units over an entire winter heating season in actual residential installations.

The task of further design optimization was addressed in the first phase of this study. The approach taken was to make modifications in the prototype low-emission furnace described in Reference 4 and to retest the unit in the Rockwell furnace laboratory. Eventually, this led to the construction and verification testing of a second, all-new integrated furnace unit. The results of this effort are summarized in a paper presented at EPA's Second Stationary Source Combustion Symposium (Reference 1).

The above effort was carefully scheduled so that the second phase, field verification, would be initiated early summer of 1977 to allow time for construction and installation of six integrated furnaces for testing in the 1977-78 winter heating season. The effort and the results of the 1977-78 heating season field testing of the integrated low-emission furnaces are the primary subjects of this paper.

FIELD TEST PREPARATION

DESCRIPTION OF THE INTEGRATED FURNACES

The effort in the first phase of this contract (Reference 1) was to finalize a configuration that incorporated the low-emissions design criteria and applied fuel-conserving techniques into a viable, commercially producible furnace unit. Six furnaces of this configuration would then be constructed for field testing.

The most expedient way of constructing only six furnaces is to purchase commercially available units and institute the desired modifications. The Lennox Industries Model 011-140 furnace was selected as the foundation for the modifications because of its compact heat exchanger and outside dimensions. Figure 1 is a line drawing of the integrated furnace configuration surrounded by photographs of the modified components. Most components are minor refinements of laboratory prototypes. The finned firebox, however, received major refinements for the field test configuration, changing from welded-steel fabrication to cast-iron formed for mass producibility. The fin heights and placements were changed for better temperature distribution to reduce internal stresses, thereby increasing potential service life. A carbon-steel ring integrally attached into the top of the cast firebox facilitated mating of the stock heat exchanger by conventional welding.

Baffles were added along the side walls (see Figure 2) to assure air flow to the finned firebox. These baffles continue up alongside the heat exchanger panels to reduce bypass flow. The firebox and heat exchanger compartment is insulated on all sidewalls with 1-in. "Cerafelt" insulation, reducing cabinet losses to near zero.

The burner, also shown in Figure 2, incorporates an optimized head, quiet stator, oversized static disc, and a standby draft control assembly with microswitch safety circuitry. The burner head is a nonretention type, using the plug-flow, low-emissions design criteria and fabricated from 22-gauge, Type 310 stainless steel sheet stock. To reduce feed-system induced pulsations, a quiet stator on the blower and an oversized static disc in the blast tube are incorporated in the optimum burner. The draft control assembly serves a twofold purpose of reducing standby heat losses by convection, and thereby maintaining the temperature of the firebox for a cleaner start on the next firing.

The integrated furnace system is completed with a "sealed-air" subsystem, which transports outside air to the burner and the flue damper. This reduces dwelling heat losses through the burner and damper. The subsystem consists of 7-in. diameter insulated ducting from an opening to the outside, to an enclosure around the flue damper, and continuing on with 4-in. diameter ducting to the top of the burner vestibule. Immediately under the entry to the vestibule is a filter box to assure consistent burner blower characteristics. The louvers in the vestibule cover are closed over by sheet metal, thereby "sealing" this air system from the dwelling.

The complete integrated system is approximately 75 lb heavier than the original Lennox 011-140, primarily because of the intentionally massive heat-retaining firebox.

TEST LOCALE SELECTION

Three field test units were located in each of two test locales where oil heat is used in a substantial fraction of single-family homes and which have distinctly different winter climates. Winter climatic data averaged over several years were reviewed for approximately 35 cities, most of which are distributed throughout the New England, Great Lakes, and Northern Midwestern States. All cities considered have normal accumulative degree-days (based on $65^{\circ}F$) exceeding 4500 for the 9-month period of September through May. Attention was also directed to nonclimatic factors such as oil usage patterns, predominant types of residential construction, state and local code requirements, availability of local support, and logistical requirements. The cities selected for the field tests were Boston, Massachusetts, and Albany, New York.

Boston's Atlantic shoreline location provides a maritime climate, and the Appalachian mountain range isolates Albany, New York, to a continental climate.

With the completion of the selection of the two cities, effort was immediately started on establishing subcontractor support. Both cities were visited by Rockwell personnel, the field test plan was presented to several contractors, and, through standard bidding procedures, commitments were established with two of the contractors, one in each city.

SELECTION OF HOST SITES

A list of potential host dwellings was supplied by each of the two service contractors from their existing customer lists. The selection of the six host sites (single-family dwellings) was based on criteria that included consideration of (1) dwelling construction, (2) dwelling location, (3) existing dwelling furnace installation, (4) fuel usage history, and (5) host family. The final selection resulted in six dwellings of a variety of characteristics that are listed in Table I. The dwellings range from 14 to 80 years of age, one to five occupants, and a poor fuel utilization of 3.52 to the best at 11.48 degree-day per gallon of fuel. This fuel utilization factor is based on the fuel consumption and climatological histories of the prior two heating seasons. All of the dwellings, with the exception of Woodbine, have insulation or insulative design incorporated in the wall surfaces. The Woodbine dwelling has no insulation and the greatest exposed wall surface, and the effect on fuel utilization is very obvious in Table I. All host dwellings have been firing No. 2 fuel oil at 0.79 ml/s (0.75 gph), which is the same as the installed integrated furnace, so as to alleviate any changes in efficiency induced by changes in rate of heat delivery.

The furnaces being replaced represent a wide spectrum, from a 20-year old unit representing furnaces near the end of their service life, to a 3-1/2 and a 5-year old Lennox 011-140 representing the most modern-design, commercially available furnace. Coincidentally, the Lennox 011-140 is the foundation of the integrated furnace body and was selected because of its compact design.

FIELD INSTRUMENTATION

Monitoring of the pollutant emissions is the primary scientific objective of the field test; however, the effect of pollution reduction devices on fuel utilization is also of great concern in these times of energy shortages. Therefore, the field test instrumentation consisted of two sets of equipment with different monitoring techniques, each set dedicated to one of the two areas of concern. The pollutant emissions measurement equipment consisted of a number of gas analyzers, assembled into a mobile unit and transported to each site on a periodic basis. The thermal efficiency measurement equipment consisted of one programmable data logger system and five supplementary recorders, all operating on a continuous monitoring basis.

Emissions Monitoring Mobile Laboratory

The pollutants of concern are oxides of nitrogen (NO_x), carbon monoxide (CO), unburned hydrocarbons (UHC), and smoke. Carbon dioxide (CO_2) and oxygen (O_2) are components also measured to accurately establish the burner operating conditions. The instruments to measure these gas components at flue gas concentrations were available in the Rockwell furnace laboratory. The instruments were removed from the stationary consoles and remounted, along with the required supplementary systems, into two rack assemblies designed to fit into the freight bay of a 3/4-ton Ford van. The two assembled instrumentation modules are shown in Figure 3 alongside the carrier vehicle. Visible on the modules are the primary instruments, strip chart recorders, hydrogen generator, calibration gas cylinders, sample pumps, gas valves, and flowmeters. Figure 4 shows Instrument Module 1 installed in the vehicle on rubber vibration isolation mounts, six of which are visible in the photograph along the bottom of the module. The enclosed bay of the vehicle is completely insulated with fire-retardant "ethafoam" for the winter duty. The white surface of the foam slabs appears as the floor of the van in this photo. Table II lists the capabilities of the instruments in the emissions-monitoring mobile laboratory along with the methods used for analyses. Although the chemiluminescent NO analyzer is equipped with a NO_2 to NO converter allowing it to measure NO_x ($NO + NO_2$), no attempt has been made thus far to measure the NO_2 component in the field, because of the requirement for a condensation-free (heated) sample transport line. Assembly of a heated line system is planned, and the NO_2 concentration will be checked in the field to confirm previous laboratory readings.

The CO and CO_2 analyzers use the method of absorption of infrared energy, and they require well-stabilized cell operating conditions. To minimize destabilizing interruptions in electrical power to these instruments, the mobile laboratory has two 120 V ac power systems. The primary system consists of two passive, external power supply circuits with provisions for connection to the dwelling's 120 V ac power circuit. This, of course, provides only for the stationary mode of operation. To keep the infrared cells operating continuously, a 12 V dc to 120 V ac power inverter provides a secondary source of electrical power for the in-transit mode. The result of having this primary-secondary electrical system has been reliable performance from the CO and CO_2 analyzers through 10 months of varying ambient conditions and 8000 miles of travel duty (i.e., vibration).

The flue gas sampling train consists of several elements that condition and transport the gas from the basement furnace installation to the instruments in the van, which is located typically about 25 m (80 ft) away. The sample is drawn by diaphragm-type suction pumps located within each instrumentation module; the total flow rate required is approximately 1.0×10^{-4} m^3/s (13.0 scfh). The sample is extracted from the flue by a stainless steel probe and drawn through a short length of T.F.E. (Teflon) tubing to an ice-cooled condensibles and particulates trap, where nearly all of the condensibles and particulates are removed by the cooling effect and glass-wool filter element. A coil of stainless steel tubing is available for attachment to the probe for sampling of gases from the combustion zone. This acts as an air-cooled heat exchanger to lower the combustion gas temperature to a tolerable level for the Teflon tubing. The removal of condensibles at this point is important to reduce the likelihood of plugging by freezing of the water when the sample is transported outdoors to the van through a 30-m (100-ft) length of Teflon tubing. The tubing connects to an external fitting on the vehicle, and thereafter the gas sample is carried internally by stainless steel tubing to a second glass-wool particulates filter. The sample path then splits and the portion destined for the infrared analyzers is dried further by passage through a desiccant ($CaSO_4$) column before being admitted to the instruments. The second gas sample path leads directly to the NO/NO_x and the UHC analyzers, avoiding any chemical desiccants that may influence the analyses. Calibration gases are available to each instrument through 4-way gas valves located just ahead of sample flowmeters that lead into each instrument.

Thermal Efficiency Data Loggers

The commercial thermal efficiency rating method generally used in the industry today is the steady-state operation, flue-gas loss method. This method uses only the measurement of flue gas CO_2 concentration and net temperature to determine air/fuel ratio (i.e., relative heat input), and unused heat energy output, from which the ratio of heat-out to heat-in is derived. This method is a useful indicator but does not account for many of the losses associated with furnaces in actual operation. The combination of the cyclical nature of operation of fired-furnace heating systems and variables contributed by the loose control tolerances of the subsystems produces complex heat loss characteristics. It was concluded, however, that evaluation of the actual operating thermal efficiency would provide valuable new data, not only to this study of balancing emissions with efficiency, but also to attract the solely efficiency-minded sector into areas of environmental concern.

Because of the large number of variables affecting the operating cycle (e.g., weather and control inconsistencies), a large number of cycles would have to be measured to provide a statistically valid data base. To accomplish this task of evaluating installed operating efficiency, a programmable data logger system was assembled to continuously record firing cycle efficiency and timing parameters. Supplementing this system were time recording data loggers attached to the five other furnaces to accurately monitor furnace utilization. The ultimate objective of this dual path scheme was to establish overall heating season thermal efficiency values for all six furnaces by correlating efficiency to cycle timing and applying the correlation to cycle timing data acquired over the entire season.

Programmable Data Logger--

The programmable data logger system was assembled around a Hewlett-Packard System 3051A, which consists of a 10-channel scanner unit, a digital multimeter, and a programmable controller. Figure 5 shows that attached to this system are two channels of ac voltage sensing, five channels of temperature measurement (Chromel-Alumel thermocouples and a thermistor), and one channel of differential pressure information. Channel 1 senses burner power to determine the boundary of the firing cycle and the duration of heat input. Channel 2 senses warm-air fan power, which is only used as a signal for measurement of heat output parameters. Channel 3 is return air temperature required for both temperature gain and air flow rate calculations. Channel 4 is a series matrix of nine thermocouples to measure output air temperature. The sum of the nine thermocouples is read in and divided by nine for an average temperature to reduce any bias if a nonuniform temperature profile exists. Channel 5 monitors maximum flue-gas temperature during the burner firing and is used in conjunction with Channel 8, burner inlet air temperature for calculation of a net flue-gas temperature. The outputs from the above four thermocouple circuits are connected to "floating" reference junctions, which are allowed to vary with ambient temperature but are stabilized in a thermally insulated enclosure. The temperature in the reference junction enclosure is monitored by Channel 7, a thermistor device, and the appropriate temperature correction is applied to all the thermocouple readings. Channel 6 is connected to a very low differential pressure transducer, 0 to 138 Pa (0 to 0.5 in. WG), which measures the pressure differential across a laminar flow element in the return air ducting. This, in conjunction with the return air temperature (Channel 3), enables the weight flow rate of heated air to be calculated.

The monitoring program continuously scans all eight channels and counts the number of scans to establish a time base. Upon sensing burner power-on, an on-time count is initiated (heat-in), and inlet air and flue-gas temperatures are monitored. Whenever warm-air fan power is sensed, the "heat-out" parameters of inlet temperature and pressure drop, and outlet temperatures are measured. Summations of these measurements are accumulated in temporary storage until the end of the cycle, which is marked by the start of the next firing. At that time, they are normalized by the number of readings to establish cycle-averaged values, which are then used in the calculation of total heat extracted from the furnace by the warm-air flow (heat-out). The values of on-time, off-time, maximum flue-gas temperature, and heat-out are stored in interim storage. When 20 firings are accumulated, the data are then transferred to magnetic tape storage. Also, if the on-time is greater than 2.8 hours or the off-time is greater than 27.8 hours, the transfer instruction is executed to secure a significant time value into storage.

A total of 4300 firings can be stored on one tape cartridge. This allows well over a month of typical furnace operation to be recorded. A data reduction program and the data on tape can then be loaded and processed by the data logger's computerized controller. The controller also has an automatic start capability that enables it to reload itself and restart the system should a power outage occur.

Cycle Time Data Loggers--

To supplement the data acquired by the above system, furnace utilization data were recorded on the remaining five furnaces. To do this, specifications were drawn up for a recording clock system that would: (1) have digital output with 1-second time resolution, (2) monitor a 120 V ac circuit, recording the moment of voltage-on and voltage-off, and distinguishing between the two, (3) provide 48-hour standby power to maintain correct time through power outages, (4) record a minimum of 8000 data points, preferably on magnetic cassette tapes, and (5) be compatible with a tape reader/computer input device. The system procured is an Instrumentation Technology Corporation Model 9676, a derivative of an earlier model, modified to the above specifications.

RESULTS OF THE 1977-78 HEATING SEASON FIELD TEST

TEST OBJECTIVES

The scientific objectives of the field test were to maintain close-to-laboratory levels of pollutant reduction and demonstrate an ability to achieve improvement in fuel consumption by careful application of the low-emissions design criteria. Consistency of performance and maintainability of the furnaces were also of interest.

The goals set on the pollutant emission concentrations were derived from consideration of both laboratory results (References 4 and 5) and a field survey (Reference 6). The emission concentration limits are expressed on a cycle-averaged basis for a fixed operating cycle of 4 minutes on, 8 minutes off. The NO emissions goal was set at 0.65 g/kg of fuel burned, a reduction of approximately 65% below the average established by the field survey. The limits for CO and UHC emissions were set at 1.00 and 0.10 g/kg, respectively, allowing no compromise of these pollutants for achieving low NO. Smoke emissions at or below No. 1 smoke spot reading on the Bacharach smoke scale were deemed acceptable.

Greater than 10 percentage points improvement in gross thermal efficiency over the average of the furnaces encountered in the field was another goal set for the integrated furnace system. Therefore, limitation for near unity stoichiometric ratio (S.R.) operating condition, S.R. = 1.20, was also imposed to aid in achieving an improvement in fuel utilization.

CLIMATIC CONDITIONS

Weather records from the Albany County Airport and the Blue Hills Observatory (Milton, Massachusetts) show totals of 7055 degree-day and 6725 degree-day, respectively, for the field test period. The test period was the second of two unusually cold winter seasons in the Northeastern and Midwestern United States. The test area encountered two severe winter storms in the months of January and February 1978. The second storm paralyzed the Boston area for 7 days, with more snowfall recorded in that area in a 24-hour period than that of the entire winter of 1972-73. Temperature extremes in the Boston area are buffered somewhat by the ocean mass (maritime climate effect), however, resulting in winter seasons warmer than those experienced in the Albany area (continental climate).

The above-reported degree-day values are based on the generally accepted 65°F baseline, from which any daily mean temperature below this value is subtracted and presented as degree-days. The heating service subcontractor in the Albany area, however, has found that use of a 70°F baseline value applied to the mean temperatures measured at the airport results in a better representation of heating oil consumption of their clientele. This is primarily because of the relatively low location of the Albany County airport in the Hudson River Valley (i.e., warmer temperatures) compared with the location of the bulk of their customers. We have found this to hold true for the three Albany test locations and have adhered to the use of this method for the Albany data. All degree-day values reported hereafter in this paper for the Albany sites are based on the 70°F reference.

PERIODIC MONITORING

The field test monitoring schedule was set up on a monthly basis. The initial furnace checkout visit occurred early in October 1977, with eight subsequent monthly visits ending in June 1978. These visits primarily involved the measurement of pollutant emissions. Many of the visits required the movement of the programmable data logger from one furnace system to another; but, generally, the efficiency-measuring systems required only the retrieval of magnetic tape data cassettes.

Pollutant Emissions Results

The results of the monthly pollutant emissions monitoring visits are presented in Tables III and IV for the Boston and Albany areas, respectively.

The data tables list the pollutant emissions goals, monthly measurements, and season averages. Although reliable heating service was maintained through the test period, difficulties in measurement of stoichiometric ratio were encountered. Inspiration of air into the negative pressure flue-pipe system upstream of the gas sampling point resulted in false readings of excess air levels. Although the flue-pipe systems were initially installed properly, thermal cycling of the systems led to changes in fit tolerances that affected the pipe joints. In one case, the galvanized piping warped significantly on the backside of the joint to the exhaust manifold (i.e., highest pipe temperature), causing approximately a 10% error in the determination of burner excess air level. Since the pollutant emission concentrations are normalized to the amount of fuel burned and not the amount of air, however, the effect of the air leaks were of only minor consequence to the emissions data. Subsequently, to monitor the integrity of the flue-pipe system, gas samples were occasionally taken from the firebox area to establish the operating stoichiometric ratio of the burner. Before this condition was recognized as a false stoichiometric ratio reading, however, burners were on occasion adjusted incorrectly to conditions below S.R = 1.20. This resulted in high carbonaceous pollutant levels or noisy (combustion roughness) operation.

Boston Area Installations--

Woodbine Site--Most of the unanticipated variables in the field test were encountered by the three Boston area installations, but these were not associated with the maritime climate effect. The Woodbine site encountered: (1) carbonization of the nozzle (see Table III), (2) flue-pipe air leaks, (3) dirty fuel supply system, and (4) unusually high fuel-bound nitrogen. The suspected carbonization of the nozzle in January led to the replacement of the nozzle and retuning of the burner because of variations in nozzle flow characteristics. Although not recognized at that time, the flue-pipe air leakage may have already been significant, causing the burner to be incorrectly adjusted below its design stoichiometric ratio operating point. This possibility is reinforced by the high smoke readings during that period. There were also complaints from the hosts of noisy operation, requiring readjustment of the burner in February to a supposedly "above design specification" air setting. Fuel samples taken during this period showed significant amounts of bottom contaminants, which were thought to be the primary cause of the high smoke emissions. Further evaluation of the unusual characteristics, however, led to a strong suspicion of air leaking into the flue. The internal gas sampling technique was tried on the subsequent visit, and it revealed a significant discrepancy between the reading taken at the flue pipe (S.R. = 1.31) and that taken above the firebox (S.R. = 1.24). Another internal sample was taken at a point higher above the firebox, at the entrance to the heat exchanger, and this also showed a higher excess air condition. This led to the belief that the leak was internal, probably at the union of the cast-iron combustor and the carbon-steel heat exchanger. Post-test disassembly of the unit, however, revealed that the leak was caused by warping of the flue pipe at a very inaccessible area, on the backside of the connection to the furnace. The negative-pressure, low-velocity system apparently allowed the cooler inspirated air to propagate down into the heat exchanger to bias the internal reading at the entrance to the heat exchanger. The season-averaged stoichiometric ratio for the Woodbine unit, even including the suspect January and February readings, is 1.23, very close to design specification. The CO and UHC averages also satisfied the respective goals.

The season-averaged NO emissions for the Woodbine site is very close to the test goal, biased slightly high by three unusually high readings taken in March, April, and May. This was attributed to a fuel-bound nitrogen level of 200 ppm, more than twice that of other oil samples analyzed. The source of this high nitrogen fuel oil stock was not traced, since there are no refinery guidelines on nitrogen composition and locating the source would only be academic. The smoke emissions field test criterion is almost fulfilled with the season average, biased by the two months of "mistuned" operation. The flue-gas temperature reflects the effect of the soot buildup with a rise in net temperature starting at the time of the initial mistuning.

Richard Site--The Richard site also experienced air leaks in the flue-pipe system. By January, a trend of increasing stoichiometric ratio conditions was noted, and at that time was assumed to be caused by degradation of oil nozzle performance. The oil nozzle was changed; however, smooth operation could not be attained at design stoichiometric ratio conditions, and the unit set at an apparently high S.R. = 1.27 (flue-gas sample) condition. The stoichiometric ratio varied on the two subsequent visits, and on the third subsequent visit (April 1978), the internal sampling technique was used, confirming the existence of air leaks biasing the stoichiometric ratio readings. It was found that the actual operating conditions in the firebox were at design specifications, in spite of the high excess air levels measured in the flue pipe. The season average is probably more on the order of S.R. ≈ 1.22 than the S.R. = 1.26 reported in Table III.

The CO emissions measured at the Richard site were acceptable, with the exception of two measurements in the early months of the heating season. The CO profiles through the 4-minute firing cycle started with a significant "spike," followed by a slow rate of decay, resulting in high cycle-averaged values. During the first month of operation, the oil bypass return line plugged, resulting in a back pressure that forced oil past the shaft seals into the burner housing. In investigating the problem, the serviceman partially disassembled the burner, which required readjustment of the air setting on the November visit. With the flue-pipe air leak developing, the burner may have been mistuned, resulting in the high CO emissions and traces of smoke. In January, the oil nozzle was changed, calling for another readjustment of the air setting, which later was shown to be very close to design specifications. The CO emissions were then under control and remained so through the remainder of the test period. The NO emissions field test goal was satisfied throughout the heating season. The goals for UHC and smoke emissions were also achieved, with consistent performance below the stated limits.

Pond Site--The Pond installation encountered only one problem that affected emissions performance — the accumulation of carbon on the nozzle. The problem was first noted at this site with a trend of increasing stoichiometric ratio (i.e., decreasing oil flow rate) requiring a nozzle change after only 2 months of service. It was first believed that the nozzle may have been "off specifications," but when another nozzle change was required on the following visit, a closer examination was made of the nozzle and burner assemblies. It was then determined that the electrodes were positioned too close to the nozzle, and repositioning was effected on this and all other test units. Thereafter, with the exception of one anomalously high reading in March, the stoichiometric ratio remained near design conditions. The limits on CO, NO, and UHC emissions were never exceeded at any time during the field test. The smoke emissions exceeded the test limit only once during the period of degraded nozzle performance, but the average for the season is well within specifications. All pollutant emissions goals were achieved at the Pond installation.

Albany Area Installations--

Gravon Site--The three integrated furnace field test installations in the Albany, New York, area performed relatively trouble free through the entire test period. The Gravon site showed a slight rise in stoichiometric ratio (see Table IV); and in February, when No. 1 Bacharach smoke reading was measured, carbonization of the nozzle was suspected. Removal of the nozzle showed only minor surface blackening, however, and the smoke reading persisted with a new nozzle installed. Finding the nozzle not to be the cause, the burner was adjusted to its as-found condition of S.R. = 1.28, in keeping with the minimum tampering field-test guideline. The isolated smoke trace recorded in February was probably induced by a fuel delivery the previous day, agitating bottom contaminants into suspension in the fuel oil. The cause of the drift in stoichiometric ratio was not identified, but the condition recovered to near design point at the end of the heating season. Pollutant emissions remained stable and controlled throughout the heating season at this installation.

Stovepipe and Fissette Sites--The Stovepipe installation did encounter a nozzle carbonization condition, which was corrected by nozzle replacement and readjustment of the spark electrode. The Fissette site showed no indication of nozzle problems and completed the heating season without adjustment. The integrated furnace test units at both these installations showed a peculiar CO emissions characteristic, the cause of which has not yet been indentified. During the warmer periods of early fall and late spring, the units show an unusually high start spike on the CO emissions profile, resulting in the cycle-averaged value being above specifications. Some effect on UHC emissions are also noted during this period. This characteristic is suppressed during the colder midwinter period, and the CO emissions goal is satisfied. Since the emissions measurements are taken on a fixed firing cycle, the temperature of the furnace components at start are relatively equal and not greatly influenced by changes in ambient temperature. The temperature of the oil transported into the furnace varies with basement temperature, however, and it is suspected that this may have an effect on the pump delivery characteristics at startup. The duration of the phenomenon is very short, making it difficult to isolate its cause. Because of the much improved performance during the colder months, the season-averaged CO emission levels for both installations are right at the limit of 1.0 g/kg. The NO, UHC, and smoke emissions for both sites are all well under the season-averaged emissions limits, thus achieving all the field-test emissions goals.

Thermal Efficiency Performance

Thermal efficiency of residential oil-fired furnaces is often rated by a steady-state operation, flue-gas heat loss method (Reference 7). This method is simple and a useful indicator, but it does not include many significant operational losses (e.g., cabinet or standby). For purposes of general comparisons, the steady-state efficiency of the integrated furnaces was measured by the flue-gas loss method and found to be between 83 and 84%, very close to the 85% maximum achievable efficiency for noncondensing flue furnace systems. These values are gross efficiency values based on the higher heating value of No. 2 fuel oil, and all efficiency values reported in this paper are computed on this basis.

Actual installed efficiencies for oil-fired, residential furnaces are substantially lower than the steady-state efficiencies, primarily because of the cyclical nature of operation. For meaningful comparisons of performance, the installed efficiency was determined in the field test for each integrated furnace. Very little comprehensive data exists on evaluation of the installed efficiency of residential heating systems, so the field test comparisons were made against the fuel utilization histories of the host dwellings for the previous two seasons. Detailed cycle-averaged efficiency versus cycle timing data were recorded for each test furnace for part of the test period, while cycle timing data were recorded through the entire heating season. From these, the relationship of overall fuel consumption can be related to cycle-averaged efficiency, and estimates of efficiency of the original furnace installations can be made. This will be accomplished before presentation of this paper by correlating cycle-averaged efficiency to timing parameters, applying the correlation to the cycle timing data for the entire season to arrive at an average efficiency for the season, and adjusting this value by the ratio of present and past fuel utilization to arrive at an estimate of prior operating efficiency.

The programmable data logger system was used to record cycle-averaged thermal efficiency and cycle timing parameters. To characterize all six test furnaces, the system monitored each furnace for a minimum of 1 month, recording more than 500 firing cycles on each furnace. The results of the data recorded are summarized in Table V, showing the average efficiency of the furnace during the period monitored. The thermal efficiencies reported here are based on actual heat delivered to the distribution system, which accounts for all furnace losses (e.g., flue gas, standby, and cabinet) exclusive of dwelling-related losses. The burner-on time-weighted averaging method is applied here, instead of a simple summation of cycle efficiencies, in order to eliminate erroneous upward biasing of the average by abnormally terminated firing cycles. The time-weighted method reduces to simple summations of heat-out and heat-in over the monitering period.

The average efficiency values presented in Table V for all six integrated furnace units are above 70%, with a mean of 74.4% and a standard deviation of ±3.8%. Typically, laboratory experimental data will produce a "scatter" on the order of ±5%, so the ±3.8% deviation is acceptable. The 80.6% performance achieved at the Woodbine site degraded approximately 2% by soot buildup during the subsequent mistuned operation period.

Although identical in construction, differences in efficiency characteristics are noted between field test units. Distinct differences are noted in the efficiency trend below 20% furnace utilization. "Dropoff" in performance varies for each furnace at low utilization. Part of the function of the inlet air draft flap is to inhibit cooldown of the furnace by restricting free convection through the furnace. The path from the firebox to the flue is not mechanically closed, however, and restricted circulation could exist in some installations and not others, resulting in the differences in standby loss characteristics. These different characteristics have impeded the resolution of an overall correlation of integrated furnace efficiency versus utilization. Although not fully defined at the time of writing, simpler evaluations of the data indicate an overall performance of the integrated furnaces to be approximately 73.5% thermal efficiency over the heating season.

The only direct comparison to the existing furnace systems is in the comparison of previous fuel utilization histories to those recorded with the integrated furnaces during the field test. The occupants were instructed to maintain thermostat temperature settings and dwelling use patterns as close as possible to the prior two seasons, leaving weather as the only variable. To correct for the differences in weather, degree-day information generally used in the heating industry to estimate fuel consumption was recorded along with the amount of fuel consumed. These data are presented in Table VI for both the original furnace and the integrated furnace service periods. The amounts of fuel consumed in each period are normalized by the respective weather factors, and these are the values used for comparisons. The changes in fuel utilization brought about by the integrated furnaces are significant, showing reductions in all cases, ranging from 10 to 30% and averaging 18.5%. The wide band of net change values is caused primarily by the wide variety of original furnaces being compared. Considering the 73.5% season-averaged thermal efficiency of the integrated furnaces and the resultant 18.5% improvement in fuel utilization, the mean season-averaged thermal efficiency of the original furnaces is calculated to be approximately 60% using a method described in Reference 5. This fits within the 55 to 75% range calculated by Janssen and Bonne (Reference 8) and the 60 to 65% range suggested by the data obtained by Turner (Reference 9). The net improvement in season-averaged gross thermal efficiency of the integrated furnaces is 13.5 percentage points, exceeding the field test efficiency goal.

CONCLUSIONS

The six integrated furnace field test units successfully completed the 1977-78 heating season with no system failures. No major component needed to be replaced, and only minor shakedown problems were encountered. The season-averaged goal of a 65% reduction in NO emissions was achieved with CO, UHC, and smoke controlled to the established limits.

The compatibility of emissions reduction with efficient fuel utilization was demonstrated. Overall improvements in fuel consumption per degree-day of 10 to 30% (18.5% average) by the six integrated furnace systems were calculated at the end of the 1977-78 field test, indicating high payback potential in careful application of low-emissions technology.

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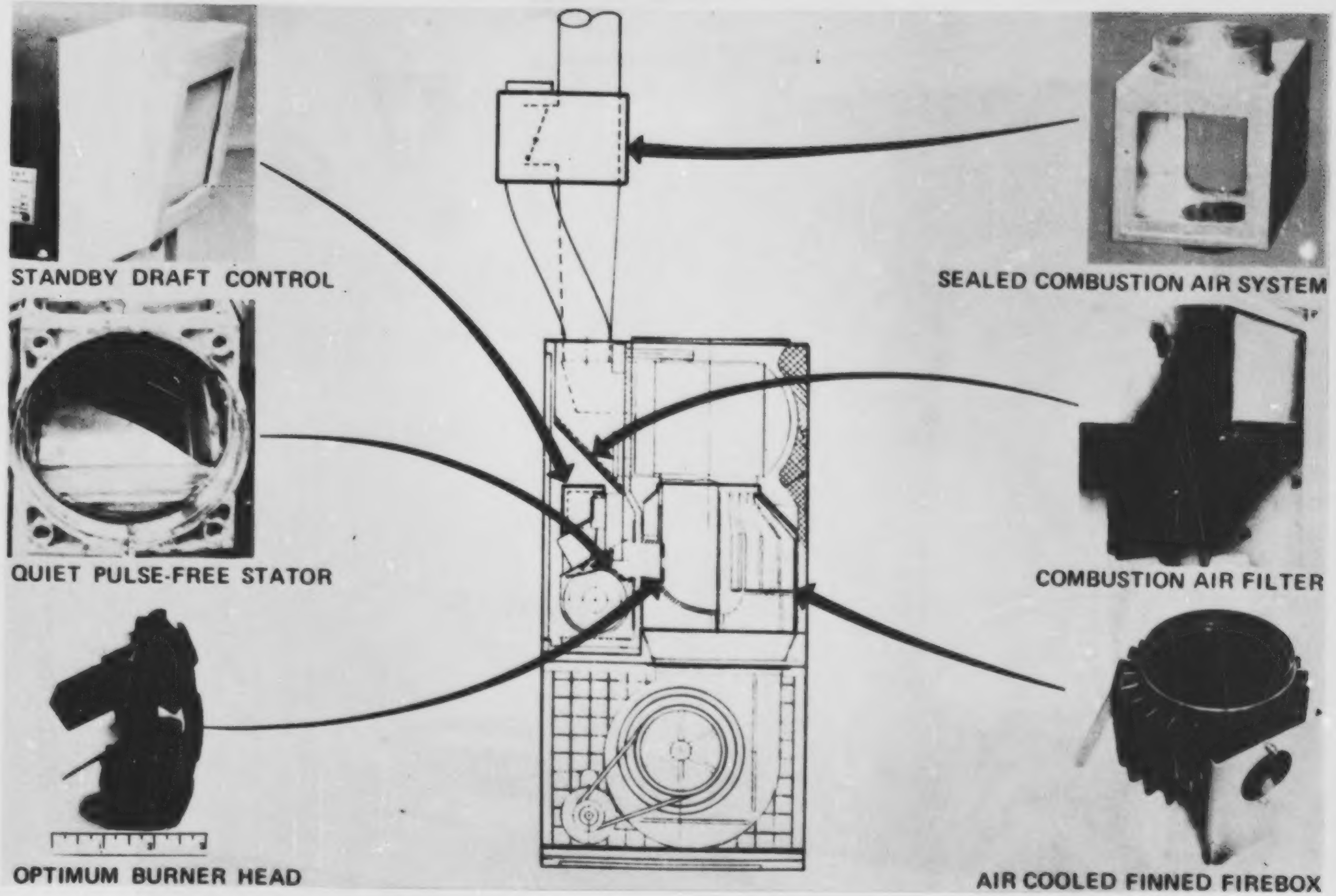
STANDBY DRAFT CONTROL
QUIET PULSE-FREE STATOR
OPTIMUM BURNER HEAD
SEALED COMBUSTION AIR SYSTEM
COMBUSTION AIR FILTER
AIR COOLED FINNED FIREBOX

Figure 1. Low-Emission Integrated Furnace Components

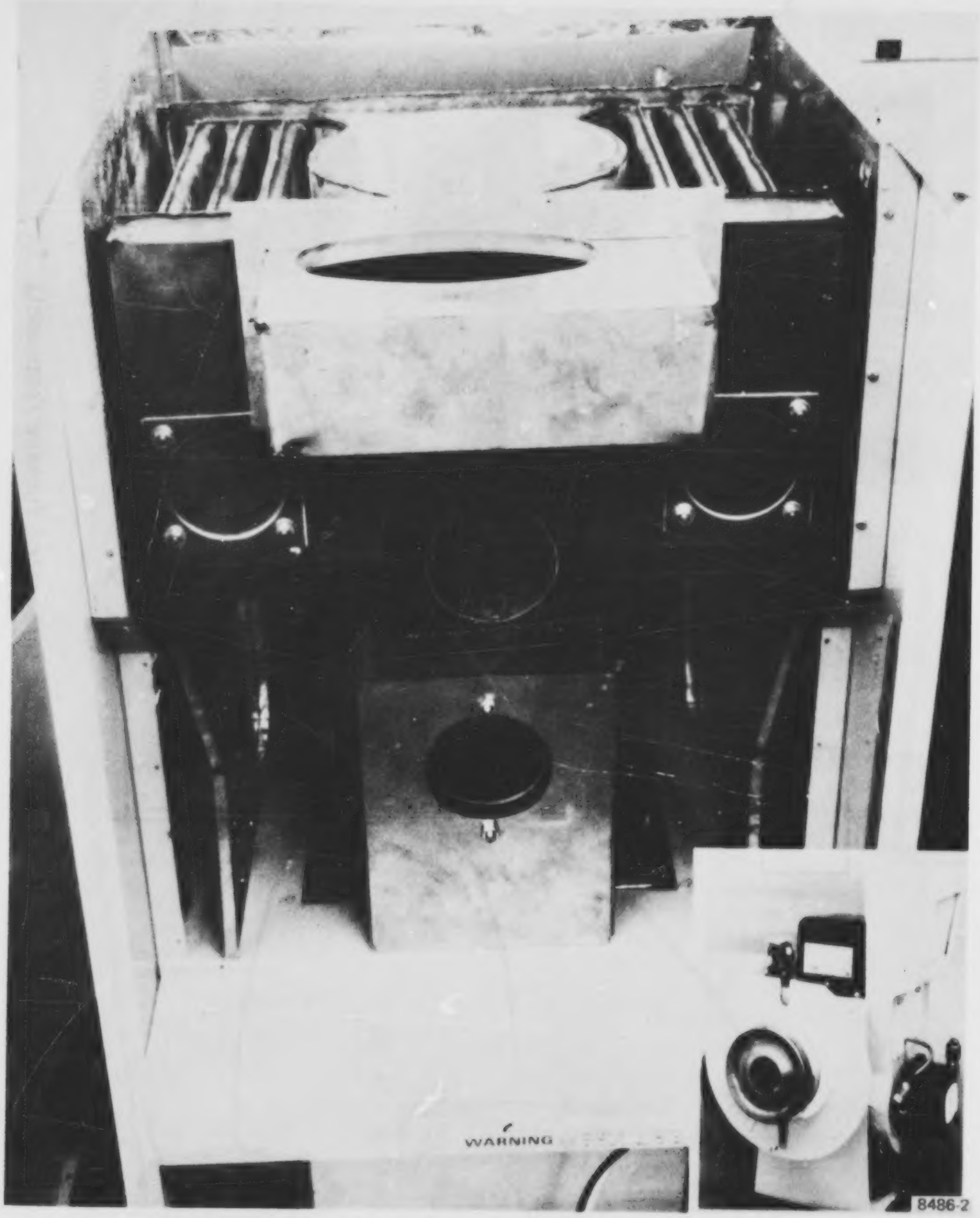
WARNING
8486-2

Figure 2. Integrated Furnace Finned Firebox and Heat Exchanger Assembly and Optimum Burner

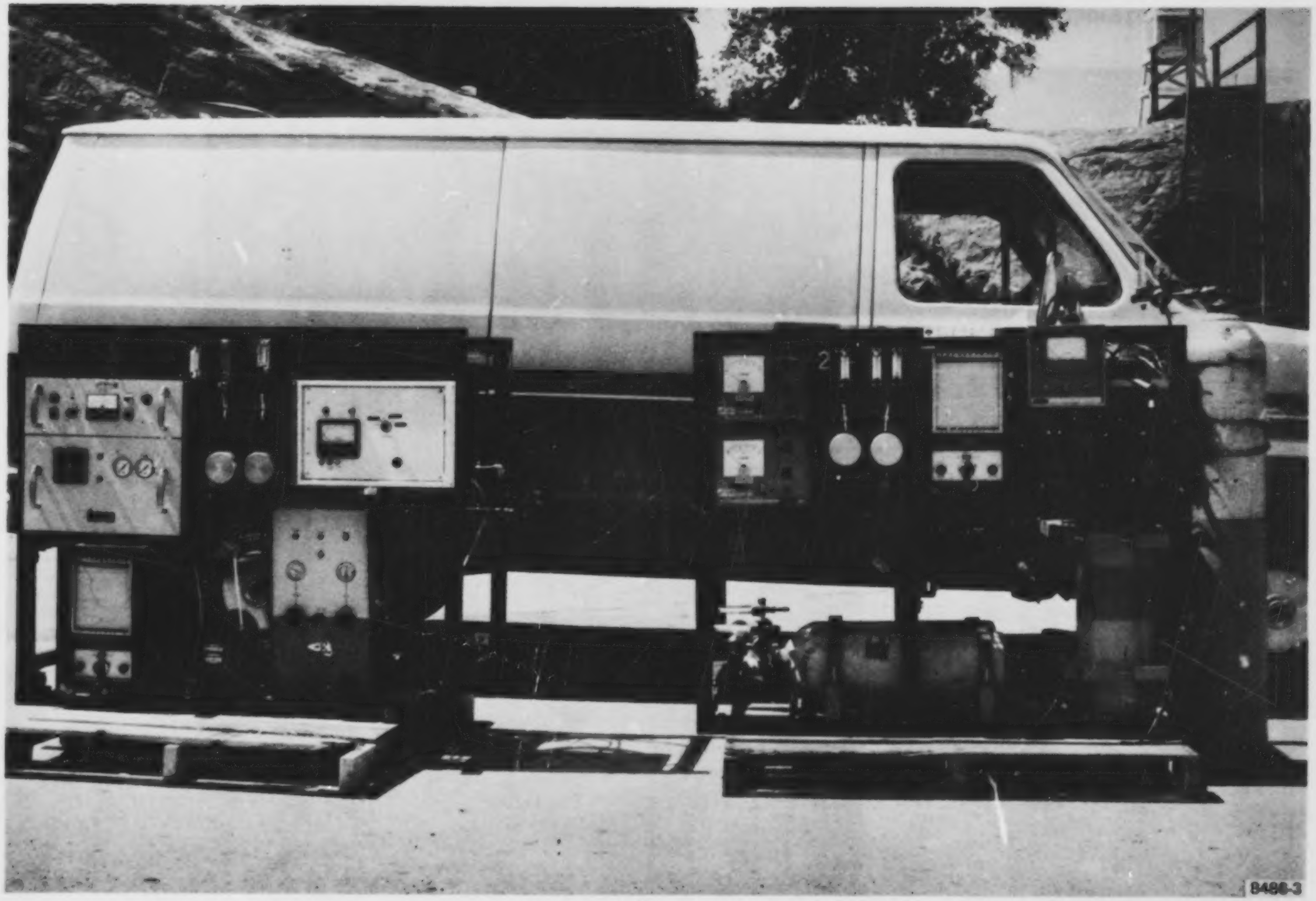

Figure 3. Rockwell International Pollutant Emissions Monitoring Laboratory

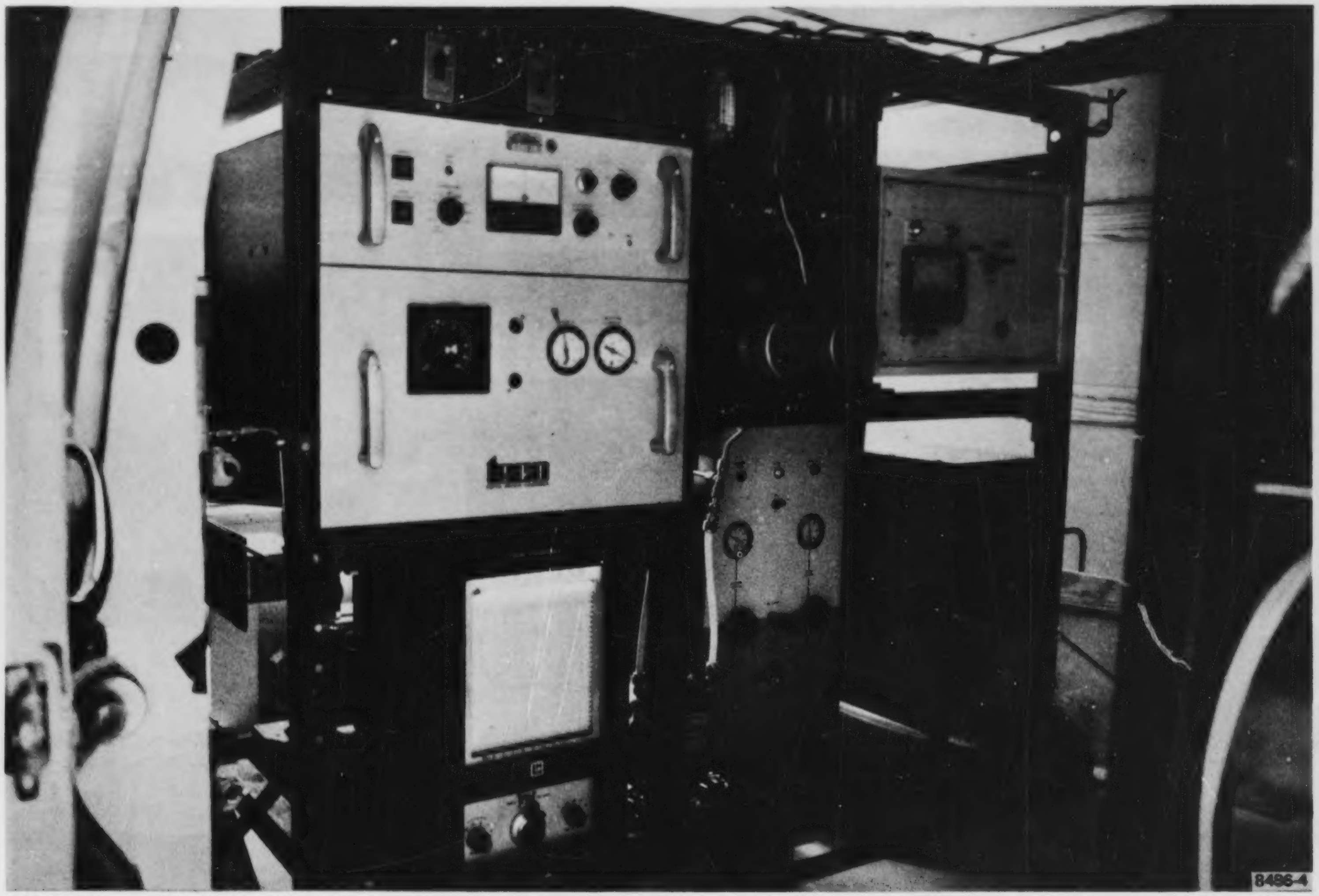

Figure 4. Flue Gas Analysis Instrument Module No. 1 Installed in the Mobile Laboratory

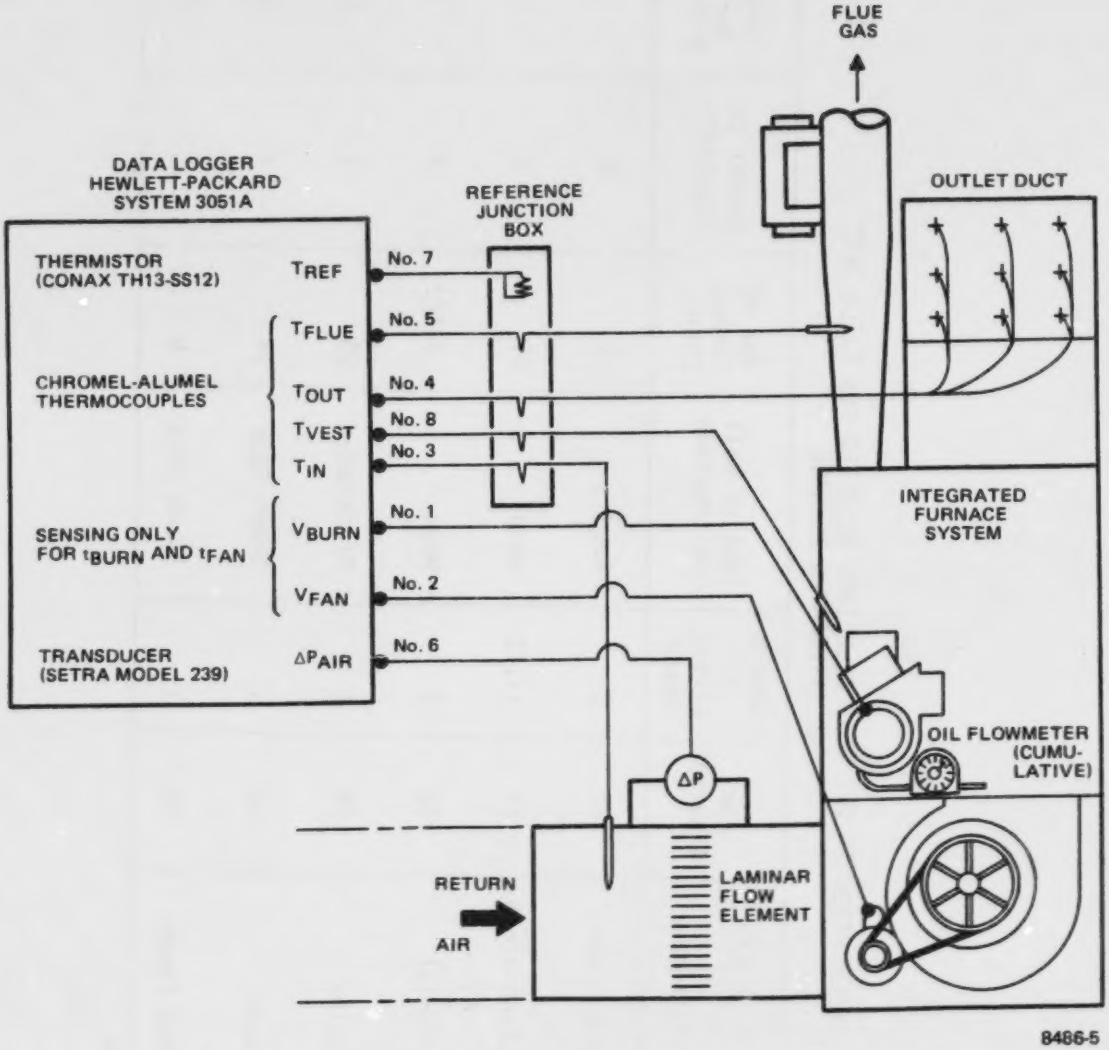
FLUE GAS
DATA LOGGER HEWLETT-PACKARD SYSTEM 3051A
REFERENCE JUNCTION BOX
OUTLET DUCT
THERMISTOR (CONAX TH13-SS12)
T_{REF}
No. 7
T_{FLUE}
No. 5
CHROMEL-ALUMEL THERMOCOUPLES
T_{OUT}
No. 4
T_{VEST}
No. 8
T_{IN}
No. 3
INTEGRATED FURNACE SYSTEM
SENSING ONLY FOR t_{BURN} AND t_{FAN}
V_{BURN}
No. 1
V_{FAN}
No. 2
TRANSDUCER (SETRA MODEL 239)
ΔP_{AIR}
No. 6
OIL FLOWMETER (CUMULATIVE)
ΔP
RETURN AIR
LAMINAR FLOW ELEMENT
8486-5

Figure 5. Schematic of Automatic Field Test Furnace Efficiency Data Acquisition System

TABLE I

DESCRIPTION OF THE HOST DWELLINGS SELECTED FOR FIELD TEST OF THE INTEGRATED FURNACE

Test Site	Type of Archi-tecture	Age (Years)	Levels of Living Space	Type of Wall Construction	Age of Furnace (Years)	Number of Occupants	Average K-Factor (D-D/gal.)*
Woodbine Street Newton, MA	Wood Frame	80	3	Wood	5	2	3.52
Richard Road Needham, MA	Raised Ranch	21	1-1/2	Wood	21	2	7.84
Pond Avenue Brookline, MA	Colonial	32	2	Wood	3-1/2	3	8.04
Gravon Drive Delmar, NY	Duplex	20	1	Brick/Wood	20	1	10.92
Stovepipe Road Clarksville, NY	Ranch	14	1	Sheet Rock	14	4	10.49
Fissette Drive Feura Bush, NY	Wood Frame	25	1	Sheet Rock	5	5	11.48

*Degree-day per gallon

TABLE II

FLUE GAS EMISSIONS MOBILE LABORATORY INSTRUMENTATION

Species	Range (Resolution)	Instrument Manufacturer and Model	Measurement Method
CO	0 to 1500 ppm (2 ppm)	MSA LIRA 300	Infrared
CO_2	0 to 15% (0.1%)	MSA LIRA 300	Infrared
NO/NO_x*	0 to 1000 ppm (1 ppm)	TECO 10A	Chemiluminescent
O_2	0 to 25% (0.2%)	Beckman	Polarographic
UHC	0 to 3000 ppm (2 ppm)	MSA	H_2 Flame Ionization
Smoke	0 to 9 Bacharach Scale	Bacharach	Hand Pump
Temperature	0 to 500°F (2°F)	—	Mercury Thermometer

*Special heated sampling train required for NO_2 measurement

TABLE III

1977-78 INTEGRATED FURNACE FIELD TEST POLLUTANT EMISSIONS SUMMARY FOR THE BOSTON AREA INSTALLATIONS

Field Test Location	Stoich. Ratio	CO (g/kg)	NO (g/kg)	UHC (g/kg)	Smoke Bach-arach	Net T_{FG} (°C)	Date
Test Goals	1.20	≤1.00	≤0.65	≤0.100	≤1.0	–	
Woodbine St. Newton, MA Unit 5	1.23	0.65	0.558	0.065	0.5	134	Oct 1977
	1.23	0.39	0.679	0.028	0.7	132	Nov 1977
	1.21	0.80	0.498	0.027	0.8	135	Dec 1977
	1.22*	0.40	0.589	0.060	2.5	167	Jan 1978
	1.27†	0.59	0.579	0.072	4.5	173	Feb 1978
	(1.24)	0.88	0.845	0.090	0.2	178	Mar 1978
	(1.22)	0.87	0.876	0.103	0.4	192	Apr 1978
	(1.22)	0.86	0.952	0.070	0	174	May 1978
	(1.24)	0.84	0.619	0.065	0	163	June 1978
	1.23	0.70	0.688	0.064	1.1	161	Average
Richard Road Needham, MA Unit 4	1.23	0.45	0.690	0.065	0.3	144	Oct 1977
	1.22†	5.60	0.350	0.050	0.6	–	Nov 1977
	1.26†	2.97	0.447	0.048	0.4	–	Dec 1977
	1.27*†	0.68	0.507	0.019	0.5	140	Jan 1978
	1.45†	0.54	0.517	0.033	0	147	Feb 1978
	1.24†	0.68	0,470	0.036	0	156	Mar 1978
	1.19**	0.72	0.585	0.060	0	142	Apr 1978
	1.23	0.81	0.610	0.028	0	153	May 1978
	1.22	0.81	0.647	0.043	0	138	June 1978
	1.26	1.47	0.536	0.042	0.2	146	Average
Pond Avenue Brookline, MA Unit 1	1.22	0.32	0.583	0.065	0.5	158	Oct 1977
	1.30	0.78	0.570	0.069	2.0	174	Nov 1977
	1.21*	0.59	0.532	0.041	0	169	Dec 1977
	1.20*	0.55	0.565	0.020	0	169	Jan 1978
	1.24	0.47	0.580	0.038	0.5	169	Feb 1978
	1.31	0.46	0.590	0.043	0.1	186	Mar 1978
	1.18	0.60	0.601	0.038	0	170	Apr 1978
	1.23	0.59	0.630	0.019	0.1	164	May 1978
	1.19	0.60	0.606	0.018	0	140	June 1978
	1.23	0.55	0.584	0.039	0.4	167	Average

* New 0.75-70°-A nozzle installed
** Flue pipe joints sealed
† Air leak suspected
( ) Combustion gas analysis

TABLE IV

1977-78 INTEGRATED FURNACE FIELD TEST POLLUTANT EMISSIONS SUMMARY FOR THE ALBANY AREA INSTALLATIONS

Field Test Location	Stoich. Ratio	CO (g/kg)	NO (g/kg)	UHC (g/kg)	Smoke Bach-arach	Net T_{FG} (^{o}C)	Date
Test Goals	1.20	≤1.00	≤0.650	≤0.100	≤1.0	—	
Gravon Road	1.22	0.41	0.590	0.028	0	159	Oct 1977
Delmar, NY	1.22	0.52	0.586	0.082	0	160	Nov 1977
Unit 2	1.24	0.49	0.494	0.042	0	153	Dec 1977
	1.31	0.52	0.522	0.050	0	160	Jan 1978
	1.28*	0.68	0.527	0.039	1.0	181	Feb 1978
	1.25	0.56	0.529	0.057	0	148	Mar 1978
	1.29	0.78	0.585	0.036	0	166	Apr 1978
	1.27	0.67	0.641	0.034	0	152	May 1978
	1.24	0.53	0.676	0.037	0	147	June 1978
	1.26	0.57	0.572	0.045	0.1	158	Average
Stovepipe Road	1.21	1.12	0.466	0.018	0	137	Oct 1977
Clarksville	1.21	2.23	0.310	0.110	0	150	Nov 1977
Unit 6	1.31	1.22	0.420	0.040	0.4	146	Dec 1977
	1.23*	0.49	0.540	0.019	0	168	Jan 1978
	1.20	0.52	0.476	0.027	0.1	176	Feb 1978
	1.23	0.65	0.613	0.046	0	161	Mar 1978
	1.21	0.72	0.583	0.024	0	158	Apr 1978
	1.21	0.75	0.535	0.018	0	—	May 1978
	1.18	1.25	0.636	0.018	0	161	June 1978
	1.22	0.99	0.509	0.036	0.1	157	Average
Fissette Drive	1.22	2.24	0.552	0.064	0	126	Oct 1977
Feura Bush, NY	1.19	1.27	0.525	0.400	0	152	Nov 1977
Unit 3	1.20	0.83	0.493	0.063	0	132	Dec 1977
	1.18	0.55	0.521	0.036	0	138	Jan 1978
	1.19	0.76	0.582	0.050	0	148	Feb 1978
	1.24	0.65	0.493	0.043	0	149	Mar 1978
	1.20	0.76	0.529	0.050	0	166	Apr 1978
	1.19	0.91	0.485	0.045	0.1	147	May 1978
	1.19	1.46	0.637	0.061	0	134	June 1978
	1.20	1.05	0.535	0.090	0	144	Average

*New 0.75-70^{o}-A nozzle installed

TABLE V

TABULATION OF INTEGRATED FURNACE CYCLE-AVERAGED THERMAL EFFICIENCY, UTILIZATION, AND TEST PERIOD WEATHER DATA

Furnace Test Site	Furnace Efficiency ($\bar{\eta}_t$,%)	Furnace Usage ($\bar{t}_R$, %)	Average Degree-Day/Day	Test Period
Woodbine Street MA (Unit 5)	80.6	24	14	Oct-Nov 1977
		48	34	Dec 1977
Richard Road MA (Unit 4)	77.1	32	37	Dec 1977 to Jan 1978
Pond Avenue MA (Unit 1)	73.0	34	43	Jan 1978
Gravon Road NY (Unit 2)	70.5	29	52*	Feb-Mar 1978
Stovepipe Road NY (Unit 6)	73.5	14	39*	Mar-Apr 1978
Fissette Drive NY (Unit 3)	73.2	13	24*	Apr-May 1978
	70.4	5	10*	May-June 1978

*Based on 70^{0}F reference

where: $$\bar{\eta}_t = \frac{100 \cdot \Sigma\left(t_{on} \cdot \eta\right)}{\Sigma t_{on}} = \frac{\frac{100}{\dot{w}_{oil} \cdot h_c} \cdot \Sigma Q_{out}}{\Sigma t_{on}} = \frac{100 \cdot \Sigma Q_{out}}{\Sigma Q_{in}} \; (t_{on} \text{ -weighted})$$

$$\bar{t}_R = \frac{100 \cdot \Sigma t_{on}}{\Sigma t_{on} + \Sigma t_{off}}$$

TABLE VI

EFFECT OF INTEGRATED FURNACE ON FUEL OIL CONSUMPTION

Test Site	Previous 2 Winters			Integrated Furnace 1977-78 Field Test			Net Change (%)
	Fuel (gal.)	Weather (D-D)*	Gal. per D-D	Fuel (gal.)	Weather (D-D)*	Gal. per D-D	
Woodbine Street Newton, MA Unit 5	3543	12489	0.2837	1455	6108	0.2383	-16.0
Richard Road Needham, MA Unit 4	1618	12679	0.1276	710	6693	0.1061	-16.9
Pond Avenue Brookline, MA Unit 1	1578	12679	0.1244	722	6478	0.1114	-10.4
Gravon Drive Delmar, NY Unit 2	1532	16722	0.0916	512	8171	0.0626	-31.7
Stovepipe Road Clarksville, NY Unit 6	1593	16722	0.0953	563	8058	0.0699	-26.6
Fissette Drive Feura Bush, NY Unit 3	1457	16722	0.0871	614	7760	0.0791	-9.5
						Overall Average	-18.5

*Degree-Day, ^{o}F-Day (Reference temperature: MA = 65^{o}F, NY = 70^{o}F)

SESSION II

UTILITY AND LARGE INDUSTRIAL BOILERS

DAVID G. LACHAPELLE
SESSION CHAIRMAN

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STATUS OF NO_X CONTROL IMPLEMENTATION FOR UTILITY BOILERS

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ABSTRACT

Utility boilers currently represent the largest contributors to total stationary source NO_x emissions in the U.S. and their contribution is projected to remain significant through the end of the century. Thus control of NO_x emissions from these sources has and will continue to receive significant attention in past and future NO_x air quality regulation strategies. Currently, modifying the combustion process conditions is the most effective and widely used technique for achieving moderate (20 to 60 percent) reduction in utility boiler emissions. Favored techniques have included staged combustion firing, flue gas recirculation, and new burner and furnace designs. This paper discusses past experience with these techniques in terms of individual and combined control effectiveness and operational problems encountered, and presents costs of implementing these controls in both retrofit application and new unit designs. Application to coal, oil, and gas fired utility boilers are treated. Finally, the status of application of these methods in existing and planned field installations is reviewed.

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SECTION 1

INTRODUCTION

Utility boilers represent the largest contributors to total stationary source NO_x emissions in the U.S. In fact, as Figure 1 shows, utility boilers were the origin of 48.3% of all stationary NO_x emissions for the year 1974 (Reference 1). Moreover, their contribution to total NO_x emissions is projected to remain significant through the end of this century. As shown in Table I, under a high energy growth projection, and assuming no additional utility control application beyond that required to meet 1971 New Service Performance Standards (NSPS), total NO_x emissions more than double by the year 2000, while the utility contribution more than quadruples. Even under a low growth scenario, and assuming aggressive promulgation of additional, more stringent, NSPS for coal fired utility boilers (258 and 215 ng/J in 1978, 172 ng/J in 1981, 120 ng/J in 1985, and 86 ng/J in 1988), total nationwide NO_x emissions increase by 25% in the year 2000 and the utility contribution increases by about 10%. Thus, it should be clear why utility boilers have received the greatest attention in past NO_x regulatory strategies, and are expected to be emphasized in future plans, both nationwide and regional, to attain and maintain NO_x ambient air quality standards.

Currently, modifying the combustion process conditions is the most effective and widely used technique for achieving moderate (20 to 60 percent) reductions in utility boiler NO_x emissions. Techniques presently in the later stages of development and application include combustion staging by means of overfire air addition (OFA) or removing burners from service (BOOS), flue gas recirculation (FGR) (for oil and gas fired boilers), and new burner and furnace designs (NBD). Coupled with all these control approaches is the use of low excess air firing (LEA). However, LEA is not considered a control method here, but instead a widely used operational adjustment.

This paper discusses past experience with each of these techniques in terms of control effectiveness and operational problems encountered, presents costs of implementing these controls in both retrofit and new unit applications, and reviews the status of application of these methods in existing and planned field installations.

SECTION 2

PROCESS IMPACTS OF NO_X CONTROL

This section summarizes the major impacts of combustion modification controls on boiler operation. The discussion is organized by fuel type.

COAL FIRED BOILERS

The effects of low NO_x operation on coal fired boilers are summarized in Table II. The table describes experience obtained through field test programs on the several units listed. The most commonly applied low NO_x technique for coal fired boilers is staged combustion through either overfire air (OFA), or burners out of service (BOOS). Average NO_x reductions of 30 to 50 percent (controlled emissions of 215 to 300 ng/J) can be expected with either technique. Flue gas recirculation has been tested, but found to be a relatively ineffective control giving only about 15 percent NO_x reduction (Reference 6). More recently new, low NO_x burner designs (NBD) have been installed on some units and found to be at least as effective as OFA. The combination of OFA with NBD has resulted in 40 to 60 percent NO_x reduction (controlled emissions of 170 to 260 ng/J).

The major concerns regarding low NO_x operation on coal fired boilers have been the effects on boiler efficiency, load capacity, water wall tube corrosion and slagging, carbon loss, heat absorption profile, and convective section tube and steam temperatures.

In most past experience with staged combustion, optimal excess air levels have been comparable to those used under baseline conditions. In these cases the efficiency of the boiler would remain unaffected if unburned carbon losses do not increase appreciably. However, in some cases when, due to nonuniform fuel/air distribution or other causes, the excess air requirement increases under staged firing, a significant decrease in efficiency may occur. From

Table II, it is seen that efficiency decreases up to 1 percent have been experienced. It is also seen that the same boiler (Widows Creek No. 5) tested at a different time with BOOS showed an average increase in efficiency of 1 percent.

Many new boilers now come factory equipped with OFA ports. Older boilers can be retrofitted with OFA ports, or can operate with minimal hardware changes under BOOS firing. BOOS firing is normally accomplished by shutting off one or more pulverizers supplying the upper burner levels. If the other pulverizers cannot handle the extra fuel to maintain the total fuel flow constant, boiler derating will be required. From Table II, it is seen that boiler derating of 10 to 25 percent is not uncommon with BOOS firing.

The possibility of increased corrosion has been a major cause for concern with staged operation. Furnaces fired with certain Eastern U.S. bituminous coals with high sulfur contents may be especially susceptible to corrosion attack under reducing atmospheres. Local reducing atmosphere pockets may exist under staged combustion operation even when burner stoichiometry is slightly over 100 percent. The problem may be further aggravated by slagging as slag generally fuses at lower temperatures under reducing conditions. The sulfur in the molten slag may then readily attack tube walls. Still, as noted in Table II, experience has generally been that no significant acceleration in corrosion rates occurs under staged firing. More recent experience has substantiated this conclusion (Reference 9). Nevertheless, the issue cannot be considered resolved until definitive results from long term tests with measurements on actual water wall tubes are available. Insofar as slagging is concerned, short term tests performed to date indicate no significant increase in slagging or fouling of tubes under staged combustion.

Increased carbon loss in flyash may occur with staged firing if complete burnout of the carbon particles does not occur in the furnace. High carbon loss will result in decreased boiler efficiency and may also cause electrostatic precipitator (ESP) operating problems. From Table II, it is seen that increases in carbon loss vary over a wide range and can be as high as 70 to 130 percent in some cases. However, increased carbon loss is not perceived as one of the major problems associated with staged combustion. If the carbon content in flyash increases to levels where it threatens to impair the operation of dust collection systems, the unburned carbon can usually be easily controlled by increasing the overall excess air level in the furnace. Although this will tend to increase stack heat losses, the decrease in boiler efficiency will be partially compensated for by reduced unburned carbon losses.

Extension of the combustion region to higher elevations in the furnace may result in potential problems with excessive steam and tube temperatures. However, among the numerous short term combustion staging tests conducted, no such problems have been reported. In some tests where furnace and convective section tube temperatures were measured directly, no significant increase was found. Changes in heat absorption profiles were also found to be minor, thus indicating no need for addition or removal of heat transfer surfaces. Superheater attemperator spray flowrates tripled in one case under OFA operation, but in all cases were well within spray flow capacities of the units. Reheater attemperator spray flowrates did not show any increase due to staged operation, thus cycle efficiencies were not affected.

Many new wall fired coal boilers are being fitted with low NO_x burners (NBD). These burners are designed to reduce NO_x levels either alone or in some cases in combination with OFA ports. Using the new burner designs has the advantage of eliminating or decreasing the need for reducing or near reducing conditions near furnace walls. Corrosion problems associated with reducing atmospheres should thus not arise with this system. Although low NO_x burner flames can be expected to be less turbulent and hence longer than flames from normal burners, the combustion zone will probably not extend any farther up the furnace than with staged combustion. Potential changes in heat absorption profile and excessive steam and tube temperatures are, therefore, less likely to occur.

As fuel and airflows are controlled more closely in NBD equipped systems, nonuniform distribution of fuel/air ratios leading to excessive CO generation or high excess air requirements should be eliminated. Boiler efficiencies should, therefore, not be affected. However, Table II shows that the efficiency of one boiler decreased slightly when retrofitted with low NO_x burners. The decrease in efficiency was mainly due to the large increase in unburned carbon loss. However, such problems noted in retrofit applications can be avoided in units specifically designed with the low NO_x burners included. Corrosion rates inferred from tests with corrosion coupons showed no significant increase with the new burners. Some BOOS tests were also carried out on the NBD equipped boiler. A substantial decrease in NO_x emissions resulted, below those already achieved with the new burners alone. However, the boiler was derated by up to 30 percent. Other potential problems noted above as being associated with staged combustion could also arise with this type of firing.

It should be emphasized that the effects of NO_x control, in many cases, will be critically dependent on boiler operating conditions. Still, with proper design of retrofit systems and adequate maintenance programs, low NO_x operation should not result in a substantial increase in operational problems over normal boiler operation. Moreover, when NO_x controls are designed into new units, potential problems can be anticipated and largely corrected.

OIL FIRED BOILERS

The effects of low NO_x operation on oil fired boilers are summarized in Table III. As the table shows the most commonly used low NO_x techniques for oil fired boilers are staged combustion and flue gas recirculation (FGR), both employed with low excess air firing. Other techniques which have been tested are water injection (WI) and reduced air preheat (RAP). However, these have found little application due to attendant efficiency losses.

Staged combustion has been applied through the use of overfire air ports (OFA) and by removing burners from service (BOOS). Typical NO_x reductions using OFA are 20 to 30 percent (controlled emissions of 150 to 172 ng/J), while BOOS has been slightly more effective giving 20 to 40 percent reductions (controlled levels of 129 to 172 ng/J). Flue gas recirculation also typically gives 20 to 30 percent NO_x reductions. The combination of staged combustion with FGR has been most effective, resulting in 30 to 60 percent reductions (controlled emissions of 100 to 172 ng/J).

The major concerns regarding low NO_x operation on oil fired boilers are effects on boiler efficiency, load capacity, vibration and flame instability, and steam and tube temperatures.

Staged combustion operation generally increases the minimum excess air requirements of the boiler, which may result in a loss in boiler efficiency. In extreme cases when the boiler is operating close to the limits of its fan capacity, boiler derating may be required. Derates of as much as 15 percent have been required in some cases due to the lack of capability to meet the increased airflow requirements at full load. In addition, under BOOS firing the fuel flow to the active burners must be increased if load is to remain constant. In many cases, it has been necessary to enlarge the burner tips in order to accommodate these increased flows.

Other potential problems attendant with applying staged combustion in oil fired boilers have concerned flame instabilities, boiler vibrations, and excessive convective section tube temperatures. However, in past experience, none of these problems has been significant. Staged operation does usually result in hazy flames and obscure flame zones. Thus new flame scanners and detectors are often required in retrofit applications. In addition, because staged combustion produces an extended flame zone, flame carryover to the convective section may occasionally occur. However, in one case where intermittant flame carryover occurred, no excessive tube temperatures were recorded.

Similarly, there are a number of potential problems which can occur in retrofit FGR applications. The most common problems, such as FGR fan and duct vibrations, can usually be avoided by good design. Other problems such as flame instability, which can lead to furnace vibrations, are caused by the increased gas velocity at the burner throats. Modifications to the burner geometry and design such as enlarging the throat, altering the burner tips, or adding diffuser plates or flame retainers may then be required.

Another potential problem associated with FGR is high tube and steam temperatures in the convective section. The increased mass velocities which occur with FGR cause the convective heat transfer coefficient to rise. This, coupled with reduced furnace heat absorption, can give rise to high convective section temperatures leading to tube failures, exceeding attemperator spray flow limits, or loss in cycle efficiency due to excessive reheat steam attemperation. Increased mass flowrates in the furnace may also cause furnace pressures to increase beyond safe limits.

The combination of staged combustion and FGR is very effective in reducing NO_x emissions. However, the problems associated with each technique are also combined. Tube and steam temperature problems in the upper furnace are particularly exacerbated, as both combustion staging and FGR tend to increase upper furnace temperatures and convective section heat transfer rates. In addition, boiler efficiencies usually decline slightly with combined staged combustion and FGR firing due to higher EA requirements and greater fan power consumption.

As with coal fired boilers, before low NO_x techniques are instituted on an oil fired boiler, it is important to assure that it is in good operating condition. Uniform burner air and fuel flows are essential for optimal NO_x control. Retrofit NO_x control systems must be designed and installed properly to minimize potential adverse effects. Many of the problems experienced in the past can now be avoided because of hindsight and experience. Thus, retrofit systems can now be designed and installed with care to avoid any potential adverse effects.

GAS FIRED BOILERS

The effects of low NO_x operation on gas fired boilers are summarized in Table IV. The most commonly applied techniques, as with oil fired boilers, are staged combustion through the use of OFA or BOOS with FGR. Typical NO_x reduction under either OFA, BOOS, or FGR is 30 to 60 percent (controlled emissions of 86 to 172 ng/J). The combination of staged combustion and FGR has resulted in 50 to 75 percent reductions (controlled levels of 65 to 129 ng/J).

The effects on low NO_x firing on gas fired boilers are very similar to those for oil fired boilers. Usually, there is no distinction between oil and gas fired boilers as they are designed to switch from one fuel to the other according to availability. Since boiler design details, NO_x control methods, and the effects of low NO_x operation are similar for gas and oil fired units, most of the above discussion of applicable NO_x control measures to oil fired boilers and potential problems resulting applies. Some effects specific to gas fired boilers alone are treated briefly in the following.

NO_x emissions oftentimes are difficult to control after switching from oil to gas firing. Residual oil firing tends to foul the furnace due to the oil ash content. Thus, NO_x control measures which have been tested on a clean furnace with gas may be found inadequate after oil firing due to the changed furnace conditions.

Boilers fired with gas usually have higher gas temperatures at the furnace outlet than when fired with oil. The upper furnace and convective section inlet surfaces are thus subject to higher temperatures with gas firing. These temperatures may increase further under staged firing or FGR. Upper furnace and convective-section tube failures and excessive steam temperatures are therefore more likely to occur with staged firing and FGR applied to gas fired boilers. The situation may be aggravated further if switching from gas fuel occurs after an oil burn, as fouling will further reduce furnace absorption and, hence, increase gas temperatures. Excessive tube temperatures will usually require derating of the system. However, problems with gas firing are not commonly encountered at present due to the scarcity of natural gas fuel.

SECTION 3

COSTS OF NO_x CONTROL

Estimated costs of applying the NO_x controls discussed in Section 2 are summarized in the following. Retrofit control costs are presented first, followed by a discussion of the incremental costs for incorporating NO_x controls in new units.

RETROFIT CONTROL COSTS

Detailed retrofit control costs were calculated using an annualized revenue requirement formulation similar to that described in References 17 and 18. Representative control costs were prepared for the boiler/control combinations shown in Table V. For each combination, preliminary engineering designs of the NO_x controls treated were prepared. This design work provided an estimate of the hardware and installation requirements for applying the retrofit controls. Up to date vendor quotes were then obtained to serve as input to the costing algorithm. All cost input data and assumptions employed are discussed in more detail in Reference 19.

TABLE V. BOILER/CONTROL COMBINATIONS COSTED

Boiler Fuel	MCR[a] (MW)	NO_x Control
Tangential/Coal	225	OFA
Opposed Wall/Coal	540	OFA
Opposed Wall/Coal	540	NBD
Opposed Wall/Coal	540	BOOS
Single Wall/Oil, Gas	90	BOOS
Single Wall/Oil, Gas	90	OFA & FGR

[a] Maximum continuous rating in MW of electrical output

It was assumed that the units being retrofitted were relatively new, say 5 to 10 years old, with at least 25 years of service remaining. As Table V shows, overfire air and new burner designs were selected as the retrofit control methods for coal firing. Burners out of service was not necessarily recommended for coal fired units, but was included to demonstrate the high cost of derating a unit, as is often the case for pulverized coal units. Burners out of service, and flue gas recirculation through the windbox combined with overfire air were selected as the retrofit control methods for the single wall oil and gas fired unit.

Estimated costs for applying the treated NO_x controls, in 1977 dollars, are summarized in Table VI. The table shows initial capital investment, annualized capital investment with other indirect costs, annualized direct costs, and total annualized cost to control. The table indicates that the preferred combustion modification generally costs between $0.50 to 0.70/kW-yr to install and operate. One major exception to this is the use of BOOS firing on coal fired units if derating is required due to insufficient mill capacity. In this instance the high cost of BOOS implementation reflects the need to purchase makeup power, and to account for lost capacity through a lost capital charge.

CONTROL COSTS FOR NEW UNITS

Estimating the incremental costs of NO_x controls for NSPS boilers is in some respects an even more difficult task than costing retrofits. Certain modifications on new units, though effective in reducing NO_x emissions, were originally incorporated due to operational considerations rather than from a control viewpoint. For example, the furnace of a typical unit designed to meet 1971 NSPS has been enlarged to reduce slagging potential. But this also reduces NO_x due to the lowered heat release rate. Thus, since the design change would have been implemented even without the anticipated NO_x reduction, the cost of that design modification should not be attributed to NO_x control.

Babcock & Wilcox has estimated the incremental costs of NO_x controls on an NSPS coal fired boiler (Reference 20). The two units used in the comparison were identical except for NO_x controls on the NSPS unit which included:

- Replacing the high turbulence, rapid-mixing cell burner with the limited turbulence dual register (low NO_x) burner
- Increasing the burner zone by spreading the burners vertically to include 22 percent more furnace surface
- Metering and controlling the airflow to each row of burners using a compartmented windbox

To provide these changes for NO_x control, the price increase was about \$1.75 to \$2.50/kW (1977 dollars). If these costs are annualized they translate to 0.28 to 0.40 \$kW-yr.

In addition, Foster Wheeler has performed a detailed design study aimed at identifying the incremental costs of NO_x control inclusive in NSPS units (Reference 21). Foster Wheeler looked at these unit designs with the following results:

	Boiler Design	Relative Cost
Unit 1:	Pre-NSPS base design	100
Unit 2:	Enlarged furnace, no active NO_x control	114
Unit 3:	NSPS design; enlarged furnace, new burner design, perforated hood, overfire air, boundary air	115.5

Assuming the cost of a pre-NSPS coal fired boiler to be about \$100/kW in 1969, or \$180/kW in 1977 construction costs (References, 22, 23, 24), the incremental cost of active NO_x controls (NBD plus OFA) is \$2.78/kW, or about \$0.44/kW-yr annualized. The Foster Wheeler estimate which includes both NBD and OFA, thus agrees quite well with the Babcock & Wilcox estimate, which includes only NBD and associated equipment.

SECTION 4

FIELD APPLICATION OF NO_x CONTROL

Given the preceding discussion of the operational effects and costs of NO_x control for both retrofit and new unit applications, Tables VII and VIII inventory the extent of existing and planned implementation of these controls. Table VII documents the application of retrofit control; Table VIII lists new units, in operation or planned, with designed-in control capability. Neither table should be considered complete, however. Table VII was compiled through direct contact with utility companies known to have participated in various EPA and privately sponsored field application tests. Table VIII was combiled largely through direct contact with utility boiler manufacturers, supplemented by published trade publication surveys. Both tables undoubtedly suffer some omissions. For example, information on planned control applications for tangential units was incomplete. However, hopefully the data represented in the tables are sufficiently complete for illustrative purposes.

Table VII illustrates that the most extensive use of retrofit controls has occurred on gas and oil fired units in California. Staged combustion through OFA or BOOS, and/or FGR have been most commonly employed. Over 14,500 MW of gas and oil fired capacity have come under control through retrofit application; representing about 6.6 percent of installed gas/oil fired capacity. Retrofit control application to coal fired units has been insignificant.

Table VIII shows that new unit controls have focused on coal fired installations, paralleling new unit sales trends (very few new gas or oil fired units have been sold since 1970). The use of new burner and furnace designs, OFA, and the combination of NBD and OFA have been the favored techniques. By the end of 1979 over 34,600 MW of coal fired capacity will have come under control for NO_x, almost all through controls incorporated into the units original design. This will represent about 14 percent of the nation's coal fired utility boiler capacity. In 1980 and beyond this fraction will, of course, increase as all new units coming on line will be built to conform to the 1971, or the proposed 1978, New Source Performance Standards.

In addition, Table VIII shows that by the end of 1979, about 12,500 MW of gas and oil fired capacity will have been installed with new unit controls. Thus a total of 17,000 MW of gas/oil fired capacity will be controlled, representing about 7.7 percent of installed capacity. No new gas or oil fired units are currently forecast to come on line after 1981.

SECTION 5

SUMMARY AND CONCLUSIONS

Modifying the combustion process conditions is currently the most effective and widely used method to effect 20 to 60 percent reductions in NO_x emissions from utility boilers. Staged combustion through overfire air addition is the favored technique for retrofit application to coal fired units, with the use of new burner designs, or new burners in combination with OFA favored for new units. Combustion staging through OFA or removing burners from service, flue gas recirculation, or the combination of FGR with staged combustion has been most extensively used in retrofit applications to oil and gas fired boilers.

Potential problems with the use of these techniques have concerned possible adverse effects on boiler efficiency, load capacity, water wall tube corrosion and slagging, fouling, carbon loss, steam temperature, and flame stability and vibration. However, recent field experience has shown that adverse effects can be minimized to acceptable levels with proper care in design for retrofit application, and largely eliminated in new unit designs.

Annualized NO_x control costs for retrofit implementation generally fall in the $0.50 to 0.70 per kW-yr. These include costs for installation of new burners or for OFA in coal fired boilers and for using BOOS in oil and gas fired boilers. Annualized incremental costs for constructing new coal fired units with provision for NO_x control fall in the $0.25 to 0.45 per kW-yr range.

By the end of 1979 approximately 7.7 percent of the oil and gas fired utility boiler capacity, and 14 percent of the coal fired capacity will be controlled using combustion modification. These percentages are projected to increase with time as:

- New, controlled, coal fired units begin operation
- Older, uncontrolled, gas/oil and coal fired units are retired
- More existing units install retrofit control in response to local regulatory demands.

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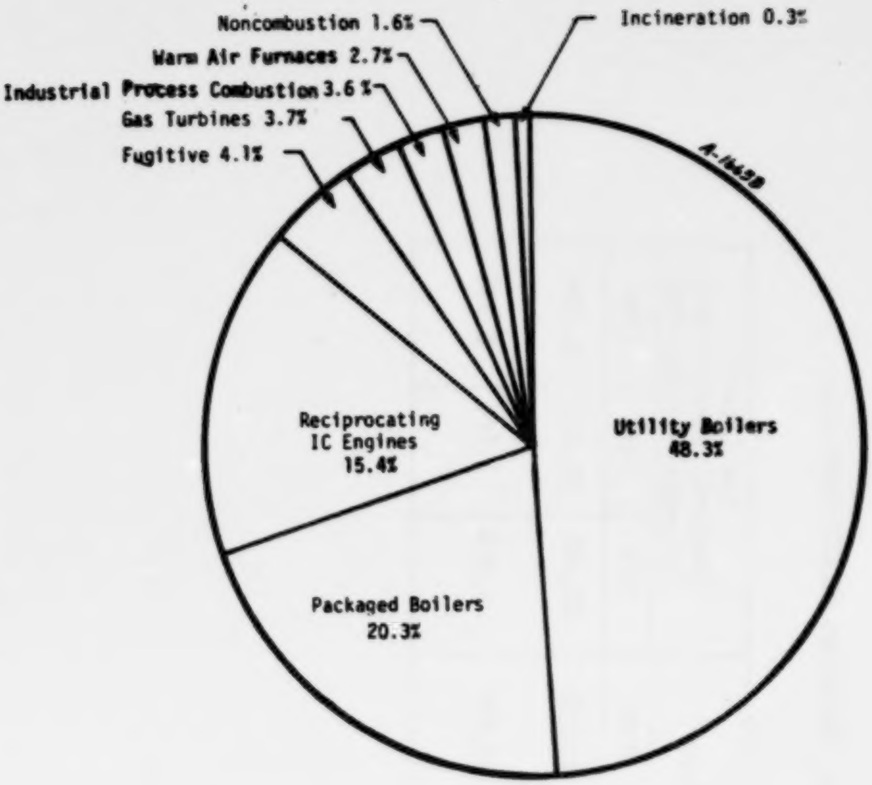

	Gg	1,000 Tons	Percent Total
Utility Boilers	5,810	6,391	48.3
Packaged Boilers	2,446	2,691	20.3
Warm Air Furnaces	320	352	2.7
Gas Turbines	440	484	3.7
Reciprocating IC Engines	1,856	2,042	15.4
Industrial Process Combustion	426	469	3.6
Noncombustion	193	212	1.6
Incineration	40	44	0.3
Fugitive	498	548	4.1
Total	12,029	13,233	100

Figure 1. Distribution of stationary anthropogenic NO_x emissions for the year 1974 (Reference 1).

TABLE I. NATIONWIDE NO_x EMISSIONS PROJECTIONS (Gg)

	High Growth No Post-1971 NSPS			Low Growth (National Energy Plan) Stringent Utility NSPS		
	1974	1985	2000	1974	1985	2000
Total Nationwide NO_x Emissions	20,931	25,857	43,852	20,931	22,251	26,084
Utility Sector NO_x Emissions	5,813	10,833	24,066	5,813	7,191	6,298

TABLE II. EFFECT OF LOW NO_x OPERATION ON COAL-FIRED BOILERS

Boiler	Low NO_x Technique	Efficiency	Corrosion[a]	Load Capacity	Carbon Loss in Flyash	Other Effects, Comments	Reference
Tangential							
Barry No. 2	BOOS	Unaffected	Measured 75% increase, but within normal range	20% derate	Slight increase	Minor changes in heat absorption profile SH attemperation increased by 70%	2
	OFA	Unaffected	Measured 70% increase, but within normal range	Unaffected	Slight increase	Minor changes in heat absorption profile SH attemperation increased over 200%	
Columbia No. 1	OFA	Unaffected	No change	Unaffected	Slight increase	Minor changes in heat absorption profile SH attemperation increased by 70%	3
Huntington Canyon No. 2	OFA	Unaffected	Measured 25% decrease, but within normal range	Unaffected	Slight increase	Minor changes in heat absorption profile No SH attemperation required	3
Barry No. 4	BOOS	Unaffected	No significant change	20% or more derate	~50% average decrease		4
Navajo No. 2	BOOS, OFA	Unaffected	No significant change	Unaffected	No change		5
Comanche No. 1	OFA	Unaffected	No significant change	Unaffected	~30% average decrease		5
Opposed Wall							
Harllee Branch No. 3	BOOS	0.6% average decrease	Slight increase	Up to 17% derate	~130% average increase		4
Four Corners No. 4	BOOS	0.6% increase	No significant change	Up to 25% derate	~50% average decrease		4
Hatfield No. 3	BOOS	0.3% decrease	--	10% derate	~30% average increase	No slagging or fouling. No significant increase in tube temperatures.	6

T-833

[a] --Denotes not investigated

TABLE II. Concluded

Boiler	Low NO_x Technique	Efficiency	Corrosion[a]	Load Capacity	Carbon Loss in Flyash	Other Effects, Comments	Reference
	FGR	0.4% decrease in boiler efficiency. Some decrease in cycle efficiency due to RH attemperation	--	Unaffected	~120% average increase	Stable flames and uniform combustion. Increase in RH attemperation. No significant increase in tube temperatures.	6
E.C. Gaston No. 1	NBD, BOOS	0.3% decrease on average (NBD baseline)	No significant increase	Up to 30% derate (NBD with BOOS)	~130% average increase (NBD baseline)	Unit retrofitted with low NO_x burners. Baseline and BOOS tests with NBD compared to baseline tests on sister boiler with no NBD.	5
Single Wall							
Widows Creek No. 5 (TVA test)	BOOS	1% decrease	Results of tests inconclusive	Unaffected	30% increase		7
Widows Creek No. 5 (Exxon test)	BOOS	1% average increase	No significant increase	Unaffected	30% average decrease		8
Widows Creek No. 6	BOOS	Unaffected	--	Unaffected	70% average increase		4,7
Mercer Station No. 1 (wet bottom)	Biased firing	Unaffected	No significant increase	Unaffected	80% average increase		8
Crist Station No. 6	BOOS	0.4% decrease	--	Up to 15% derate	60% increase		4

[a]--Denotes not investigated

T-833

TABLE III. EFFECT OF LOW NO_x OPERATION ON OIL-FIRED BOILERS

Boiler	Low NO_x Technique	Efficiency[a]	Load Capacity[a]	Vibration and Flame Instability[a]	Steam and Tube Temperatures[a]	Other Effects, Comments	Reference
Tangential							
South Bay No. 4	BOOS	Decrease in efficiency compared to LEA due to increased excess air requirements				No other adverse effects reported	10
	RAP	Unaffected due to special preheater design	--	--	--	Limited tests. NO_x control effectiveness not demonstrated.	
Pittsburg No. 7	OFA and FGR	--	Slower startups and load changes	FGR fan vibration problems	High water wall tube temperatures		11
SCE tangential boilers	BOOS and FGR	--	--	--	--	No adverse effects reported	12,13
Opposed Wall							
Moss Landing Nos. 6 and 7	OFA and FGR	Increased excess air requirements resulting in decreased efficiency	--	FGR fan and duct vibration, furnace vibration problems. Associated flame instability	--	High furnace pressures. Increased FGR and forced draft fan power consumption	11,14
Ormond Beach Nos. 1 and 2	BOOS and FGR	Increased excess air requirements resulting in decreased efficiency	10 to 15% derate due to maxed FD fan capacity	Flame instability and associated furnace vibration	--	Flame detection problems due to change in flame characteristics	12,13
	Water injection	Increased sensible and latent stack losses	--	--	--	Limited tests carried out with WI at partial loads. Excess air requirements increased	
SCE B&W Units	BOOS and FGR	FGR reduced minimum excess air requirements increasing unit efficiency	--	Boiler vibration problems	--	Flame detection problems due to change in flame characteristics	12
Sewaren Station No. 5	BOOS	--	--	--	--	Tests carried out at partial loads. No adverse effects reported. Particulate loading and size distribution unaffected.	8

[a]--Denotes not investigated

T-831

TABLE III. Concluded

Boiler	Low NO_x Technique	Efficiency[a]	Load Capacity[a]	Vibration and Flame Instability[a]	Steam and Tube Temperatures[a]	Other Effects, Comments	Reference
Single Wall							
Encina Nos. 1, 2 and 3	BOOS (2 burners on air only)	Increased unit efficiency. Some adverse effect on cycle efficiency due to lower steam temperatures	--	--	Decrease in SH & RH steam temperature	No other adverse effects reported	15
	BOOS (3 burners on air only)	Increased excess air requirements resulting in reduced efficiency	5% derate due to maxed ID fan capacity	In most tests no flame instability or blowoff noted	Intermittent flame carryover to SH inlet but tube temperature limits not exceeded	No abnormal tube fouling, corrosion or erosion noted. Increased tendency to smoke and obscure flame zone.	
Turbo							
South Bay No. 3	Water injection	6% decrease at full load	--	No flame instability noted even at high rates of WI	--	No other adverse effects reported	10
	RAP	Reduction in efficiency greater than that with water injection	--	--	--	Limited tests	
Potrero No. 3-1	OFA and FGR	Higher excess air requirements, but addition of economizer surface expected to improve efficiency	5% derate due to excessive tube temperatures	Side to side windbox oxygen cycling	Tube and steam temperature limits approached. Increased SH tube failures	Increased tendency to smoke required higher minimum excess O_2 levels. RH surface removed to avoid excessive RH steam attemperation. Larger economizer installed to compensate for RH surface removal.	11

[a]--Denotes not investigated

T-831

TABLE IV. EFFECT OF LOW NO_x OPERATION ON GAS-FIRED BOILERS

Boiler	Low NO_x Technique	Efficiency[a]	Load[a] Capacity	Vibration and[a] Flame Instability	Steam and Tube[a] Temperatures	Other Effects, Comments	Reference
Tangential							
South Bay No. 4	BOOS	Slight decrease in efficiency due to increased excess air requirements				No other adverse effects reported	10
Pittsburg No. 7	OFA and FGR	--	25% derate due to excessive steam temperatures slower load change response	Fan and duct vibration problems	High tube and RH steam temperatures		11
Horizontally Opposed							
Moss Landing Nos. 6 and 7	OFA and FGR	0.8% decrease in cycle efficiency due to RH steam attemperation	Load curtailment to 50% after oil burns due to SH tube temperature limits being exceeded	Furnace and duct vibration problems. Flame instability.	RH spray and SH tube temperature limits approached after oil burns upper wall tube failures	Furnace pressure limit approached. FGR fan power requirements increased by as much as 66%. Problems associated with switching to gas after oil burning could be eliminated only with complete water washing of furnace.	11,14,16
Pittsburg Nos 5 and 6	OFA and FGR	--	--	FGR fan and duct vibrations. Flame instability problems.	Upper water wall tube failures	Boiler initially restricted to manual operation due to problems with flame instability on automatic control	11
Contra Costa Nos. 9 and 10	OFA and FGR	--	--	FGR duct vibrations	High SH and RH steam temperatures. SH tube temperature limits being approached.	Furnace pressure limits approached after oil firing. FGR fan preheating required to reduce vibrations on cold boiler startups.	11
Single Wall							
Encina Nos. 1, 2 and 3	BOOS (2 and 3 burners out of service)	Low EA levels were possible even with BOOS, resulting in increased efficiency	No derate. Load pickup response not affected	Some pressure pulsing at corners of firebox	Some flame carryover to SH but no problems with high tube temperature or tube wastage	No other adverse effects reported	15

T-819

[a] --Denotes not investigated

TABLE IV. Concluded

Boiler	Low NO_x Technique	Efficiency[a]	Load[a] Capacity	Vibration and[a] Flame Instability	Steam and Tube[a] Temperatures	Other Effects, Comments	Reference
Turbo							
South.Bay No. 3	Water injection	10% decrease at full load	--	No flame instability noted even at high rates of WI	--	No other adverse effects reported	10
Potrero No. 3-1	OFA and FGR	Installation of larger economizer expected to improve efficiency	5% derate due to problems with high temperatures	Side to side windbox oxygen cycling	Tube metal and steam temperature limits reached at high loads	Hardware modifications included partial RH surface removal to avoid excessive RH steam attemperation. Larger economizer then installed to compensate for smaller RH surface.	11

T-819

[a]--Denotes not investigated

TABLE VI. SUMMARY OF RETROFIT CONTROL COSTS[a]

Boiler/Fuel Type	Initial Investment ($/kW)	Annualized Indirect Operating Cost ($/kW-yr)	Annualized Direct Operating Cost ($/kW-yr)[a]	Total to Cost Control ($/kW-yr)[a]
Tangential/Coal-Fired				
OFA	0.90	0.21	0.32	0.53
Opposed Wall/Coal-Fired				
OFA	0.62	0.16	0.52	0.69
NBD	2.03	0.34	0.06	0.40
BOOS	0.08	5.34	24.78	30.12
Single Wall/Oil- and Gas-Fired				
BOOS	0.30	0.05	0.44	0.49
FGR/OFA	5.71	1.14	1.91	3.05

T-870

[a]--Based on 7000-hour operating year. Typical costs only.

TABLE VII. RETROFIT UTILITY BOILER NO_x CONTROL INVENTORY*

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW	Fuel	NO_x Control	Year Online
Alabama Power Co.	Barry 2	T	CE	130	C	OFA	NAv
Los Angeles Dept. of Water & Power	Harbor 1	W	NAv	75	G,O	BOOS	NAv
	Harbor 2	W	NAv	75	G,O	BOOS	NAv
	Harbor 3	W	NAv	90	G,O	BOOS	NAv
	Harbor 4	W	NAv	90	G,O	BOOS	NAv
	Harbor 5	W	NAv	95	G,O	BOOS	NAv
	Haynes 1	W	CE	240	G,O	BOOS	NAv
	Haynes 2	W	CE	240	G,O	BOOS	NAv
	Haynes 3	HO	BW	245	G,O	BOOS, OFA	65
	Haynes 4	HO	BW	245	G,O	BOOS, OFA	65
	Haynes 5	HO	BW	350	G,O	BOOS, OFA	66
	Haynes 6	HO	BW	350	G,O	BOOS, OFA	67
	Scattergood 1	W	CE	180	G,O	BOOS	NAv
	Scattergood 2	W	CE	180	G,O	BOOS	NAv
Pacific Gas & Electric	Moss Landing 6	HO	BW	750	G,O	BOOS, FGR	71
	Moss Landing 7	HO	BW	750	G,O	BOOS, FGR	71
	Pittsburg 5	HO	BW	330	G,O	FGR, OFA	64
	Pittsburg 6	HO	BW	330	G,O	FGR, OFA	64
	Pittsburg 7	T	CE	735	G,O	FGR, OFA	72
	Contra Costa 9	HO	BW	330	G,O	FGR, OFA	65
	Contra Costa 10	HO	BW	330	G,O	FGR, OFA	65
	Potrero 3	Tu	RS	300	G,O	FGR, OFA	72
San Diego Gas & Electric	South Bay 1	W	BW	140	G,O	RAP	60
	South Bay 2	W	BW	142	G,O	OFA	62
	South Bay 3	Tu	RS	198	G,O G,O	OFA, RAP	64
	South Bay 4	T	CE	220	G,O	OFA	71
	Silvergate 1	W	BW	19	G,O	BOOS	43
	Silvergate 2	W	BW	19	G,O	BOOS	43
	Silvergate 3	W	BW	32	G,O	BOOS	48
	Silvergate 4	W	BW	32	G,O	BOOS	48
	Silvergate 5	W	BW	64	G,O	BOOS	50
	Silvergate 6	W	BW	64	G,O	BOOS	52
	Encina 1	W	BW	100	G,O	BOOS	54
	Encina 2	W	BW	102	G,O	BOOS	56
	Encina 3	W	BW	102	G,O	BOOS	58
	Encina 4	W	BW	287	G,O	FGR	73
Southern California Edison	Alamitos 1	W	NAv	175	G,O	OFA	NAv
	Alamitos 2	W	NAv	175	G,O	OFA	NAv
	Alamitos 3	T	CE	320	G,O	FGR	NAv
	Alamitos 4	T	CE	320	G,O	FGR	NAv

*Reference 25

TABLE VII. (Concluded)

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW		NO_x Control	Year Online
Southern California Edison	Alamitos 5	HO	BW	480	G,0	BOOS, FGR	65
	Alamitos	HO	BW	480	G,0	BOOS, FGR	66
	El Segundo 1	W	NAv	175	G,0	BOOS, OFA	NAv
	El Segundo 2	W	CE	175	G,0	BOOS, OFA	NAv
	El Segundo 3	T	CE	335	G,0	FGR	NAv
	El Segundo 4	T	CE	335	G,0	FGR	NAv
	Etiwanda 1	T	CE	135	G,0	BOOS	NAv
	Etiwanda 2	T	CE	135	G,0	BOOS	NAv
	Etiwanda 3	T	CE	320	G,0	FGR	NAv
	Etiwanda 4	T	CE	320	G,0	FGR	NAv
	Huntington Beach 1	W	NAv	215	G,0	BOOS, OFA	NAv
	Huntington Beach 2	W	NAv	215	G,0	BOOS, OFA	NAv
	Huntington Beach 3	HO	NAv	215	G,0	OFA	NAv
	Huntington Beach 4	HO	NAv	225	G,0	OFA	NAv
	Ormond Beach 1	HO	FW	785	G,0	BOOS, FGR, OFA	71
	Ormond Beach 2	HO	FW	785	G,0	BOOS, FGR, OFA	73
	Mandalay 1	W	NAv	215	G,0	BOOS	NAv
	Mandalay 2	W	NAv	215	G,0	BOOS	NAv
	Redondo 5	W	NAv	175	G,0	OFA	NAv
	Redondo 6	W	NAv	175	G,0	OFA	NAv
	Redondo 7	HO	BW	480	G,0	BOOS, FGR	66
	Redondo 8	HO	BW	480	G,0	BOOS, FGR	67
Southern Electric Generating Company	E. C. Gaston 1	HO	BW	270	C	NBD	60
Tennessee Valley Authority	Widows Creek 5	W	BW	125	C	BOOS	50
Western Farmers Electric Coop.	Moorland 3	Tu	RS	135	G	BOOS	75

Unit Type

HO - Horizontally opposed
T - Tangentially fired
Tu - Turbo-fired
W - Single wall fired

NO_x Controls

BOOS - Burners out of service
FGR - Flue gas recirculation
NBD - New burner or furnace design
OFA - Overfire air
RAP - Reduced air preheat

Manufacturer

CE - Combustion Engineering, Inc.
BW - Babcock & Wilcox Co.
FW - Foster Wheeler Energy Corp.
RS - Riley Stoker Corp.

Fuel

C - Coal
G - Gas
O - Oil

Others

NAv - Not available

TABLE VIII. NEW UTILITY BOILER NO_x CONTROL INVENTORY*

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW	Fuel	NO_x Control	Year Online
Alabama Electric Cooperative	Tombigbee 2	Tu	RS	255	C	NBD	78
	Tombigbee 3	Tu	RS	255	C	NBD	79
Alabama Power Co.	Miller 1	HO	BW	660	C	NBD	78
	Miller 2	HO	BW	660	C	NBD	79
	Miller 3	HO	BW	660	C	NBD	80
	Miller 4	HO	BW	660	C	NBD	80
Allegheny Power System	Pleasants 1	HO	W	600	C	OFA	78
	Pleasants 2	HO	FW	600	C	OFA	79
American Electric Power	Breed 2	HO	BW	1300	C	NBD	79
Arizona Electric Power Coop.	Apache 2	Tu	RS	203	C	NBD,OFA	77
	Apache 3	Tu	RS	203	C	NBD,OFA	78
Arizona Public Service Company	Cholla 4	T	CE	130	C	NBD	80
Arkansas Power & Light Company	White Bluff 2	T	CE	800	C	OFA	81
Austin, City of (Texas)	Decker Creek 2	HO	BW	425	G,O	OFA,FGR	77
Baltimore Gas & Electric	Brandon Shores 1	HO	BW	600	O	NBD,OFA	78
	Brandon Shores 2	HO	BW	600	O	NBD,OFA	78
Basin Electric	Laramie River 1	HO	BW	580	C	NBD	79
	Laramie River 2	HO	BW	580	C	NBD	80
Big Rivers Electric Corporation	Reid 2	NAv	BW	240	C	NBD	79
Black Hills Power & Light, Pacific Power & Light	Wyodak	HO	BW	350	C	NBD	78
Brazos Electric Power Corporation	San Miguel 1	HO	BW	448	C	NBD	79
Bryan, City of	Dansby 1	W	BW	105	G,O	OFA	78
Cajun Electric Power Coop.	Big Cajun 1	Tu	RS	540	C	NBD	79
	Big Cajun 2	Tu	RS	540	C	NBD	80
Carolina Power & Light Company	Mayo 1	HO	FW	375	C	OFA	81
	Mayo 2	HO	FW	375	C	OFA	81
	Mayo 3	HO	FW	375	C	OFA	84
	Mayo 4	HO	FW	375	C	OFA	84
	Roxboro 4A	Tu	RS	360	C	NBD	75
	Roxboro 4B	Tu	RS	360	C	NBD	76
Central Illinois Light Company	Duck Creek Site 1	W	RS	378	C	FGR	76
Central Illinois Public Service Co.	Meredosia 4	W	FW	200	O	FGR,OFA	76
Central Louisiana Electric Company	Rodemacher 2	HO	FW	550	C,O,G	FGR,OFA	82
Central Maine Power Company	Cousins 4	W	FW	600	O	OFA	78
Central Power & Light Company	Coleto Creek 1	T	CE	550	C	OFA	79
Cincinnati Gas & Electric	Miami Fort 8	HO	BW	552	C	NBD,OFA	77
	East Bend 2	HO	BW	650	C	NBD	79

*Reference 25

TABLE VIII. (Continued)

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW	Fuel	NO_x Control	Year Online
Cliffs Electric Service Company	Presque Isle 7	Tu	RS	85	C	NBD	78
	Presque Isle 8	Tu	RS	85	C	NBD	78
	Presque Isle 9	Tu	RS	85	C	NBD	79
Colorado Public Service Company	Comanche 1	T	CE	350	C	OFA	NAv
	Comanche 2	HO	BW	350	C	OFA	75
	NAv	HO	FW	500	C	OFA	80
Colorado Springs D.P.U.	New Fountain 1	W	BW	220	C	NBD	79
Colorado Ute Electric Assn. Inc.	Craig 1	HO	BW	470	C	NBD	79
	Craig 2	HO	BW	470	C	NBD	78
Columbus & Southern Ohio Electric Co.	Poston 6	T	CE	413	C	OFA	83
Commonwealth Edison	Collins 1	HO	BW	550	O	OFA,FGR	77
	Collins 2	HO	BW	550	O	OFA,FGR	76
	Collins 3	HO	BW	550	O	OFA,FGR	76
	Collins 4	HO	BW	550	C,O	NBD	77
	Collins 5	HO	BW	550	C,O	NBD	78
Consolidated Edison	Astoria 6	W	FW	800	O,G	FGR,OFA, NBD	77
Consumers Power	Campbell 3	HO	FW	840	C	OFA	80
Dairyland Power Company	Alma 6	Tu	RS	280	C	NBD,OFA	77
Dallas Power & Light Company	Martin Lake 2	T	CE	750	L	OFA	78
Dayton Power & Light	Killen 1	HO	BW	650	C	NBD	82
	Killen 2	HO	BW	650	C	NBD	80
Delmarva Power & Light	Indian River 4	Tu	RS	400	C	NBD	79
Detroit Edison	Belle River 1	HO	BW	650	C	NBD	NAv
	Belle River 2	HO	BW	650	C	NBD	NAv
	Greenwood 1	W	FW	800	O	FGR,OFA	79
Detroit Public Lighting Comm.	Mistersky 3	Tu	RS	60	O	NBD	78
East Kentucky Rural Coop.	Charleston Bottoms	HO	BW	333	C	NBD,OFA	76
Florida Power & Light Company	Manatee 1	W	FW	800	O	FGR,OFA	76
	Manatee 2	W	FW	800	O	FGR,OFA	77
	Martin 1	W	FW	800	O	FGR,OFA	80
	Martin 2	W	FW	800	O	FGR,OFA	81
Fremont, City of (Nebraska)	Wright 8	W	BW	85	C	NBD	76
Gainesville, City of (Florida)	NAv	Tu	RS	81	C	NBD	75
Georgia Power Company	Scherer 2	T	CE	818	C	OFA	82
Gulf Power	Ellis 1	HO	FW	575	C	OFA	82
	Ellis 2	HO	FW	575	C	OFA	84
Gulf States Utility Company	Nelson 5	T	CE	520	C	OFA	86
	Sabine 5	T	CE	480	O	OFA	79

TABLE VIII. (Continued)

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW	Fuel	NO_x Control	Year Online
Grand River Dam Authority	Unit 1	HO	FW	490	C	OFA,NBD	81
Hoosier Energy Division	Unit 1	Tu	RS	490	C	NBD,OFA	81
	Unit 2	Tu	RS	490	C	NBD,OFA	80
Houston Lighting & Power (Texas)	Parish 5	HO	BW	675	G,C,O	NBD	76
	Parish 6	HO	BW	675	G,C,O	NBD	76
	Cedar Bayou 3	HO	FW	750	O,G	FGR,OFA	75
Illinois Power	Havana 6	HO	BW	472	C	NBD	78
Indiana Public Service	Gibson 3	HO	FW	660	C	OFA,NBD	82
	Gibson 4	HO	FW	660	C	OFA,NBD	78
	Gibson 5	HO	FW	660	C	OFA,NBD	79
Interstate Power	Lansing 4	Tu	RS	260	C	NBD	77
Iowa Power & Light	Council Bluff 3	HO	BW	700	C	NBD	79
Iowa Public Service	George Neal 4	HO	FW	600	C	OFA	78
Iowa Southern Utilities Company	Ottumwa 1	T	CE	674	C	OFA	81
Jersey Central Power & Light Company	Coho 1	T	CE	800	C	OFA	87
	Seward 7	T	CE	800	C	OFA	84
Kansas City Board of Public Utilities	Nearman Creek 1	Tu	RS	235	C	NBD	78
Kansas City Power & Light Company	Iatan 1	HO	BW	680	C	NBD	80
	La Cygne 2	HO	BW	685	C	NBD	77
Kentucky Utilities	Ghent	HO	FW	511	C	OFA	83
Lafayette, City of	Bonin 3	W	BW	187	G,O	OFA	76
Lakeland, Florida	Plant 3, Unit 2	W	BW	125	O	FGR	75
Louisville Gas & Electric	Mill Creek 3	HO	BW	450	C	NBD	78
	Mill Creek 4	HO	BW	534	C	NBD	79
Lower Colorado River Authority	Fayette 1	T	CE	550	C	OFA	79
Mississippi Power Company	Jackson County 2	T	CE	500	O	FGR	79
Mississippi Power & Light	Andrus 1	HO	BW	750	O	FGR	74
Montana Power Company	Colstrip 3	T	CE	700	C	OFA	80
	Colstrip 4	T	CE	700	C	OFA	81
Nebraska Public Power	NAv	HO	BW	930	C	NBD	80
New Mexico Public Service Company	San Juan 1	W	FW	375	C	OFA,NBD	77
	San Juan 2	W	FW	350	C	OFA	74
	San Juan 3	HO	BW	600	C	NBD	81
	San Juan 4	HO	BW	600	C	NBD	81
New York State Electric & Gas	Lake Cayuga	HO	BW	930	C	NBD	83
New York State Power Authority	NAv	HO	FW	750	C	OFA	NAv

TABLE VIII. (Continued)

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW	Fuel	NO_x Control	Year Online
Niagara Mohawk	Oswego 5	W	FW	850	O	FGR,OFA	76
	Oswego 6	W	FW	850	O	FGR,OFA	79
Northern Indiana Public Service	Schaefer 15	HO	FW	500	C	OFA	79
Northern States Power	Sherburne Co. 3	HO	BW	800	C	NBD	80
	Sherburne Co. 4	HO	BW	800	C	NBD	81
Oklahoma Gas & Electric Company	Sooner 1	T	CE	510	C	OFA	79
Oklahoma Public Service Company	Northeastern 1	T	CE	450	C	OFA	79
	Northeastern 2	T	CE	450	C	OFA	79
Omaha Public Power	Nebraska City 1	HO	FW	575	C	OFA	79
Pennsylvania Electric	Homer City 3	HO	BW	680	C	NBD	77
Pennsylvania Power	Mansfield 3	HO	FW	880	C	OFA	80
Portland General Electric	Boardman 1	HO	FW	500	C	OFA	80
Potomac Electric Power Company	Morgantown 1	T	CE	575	C	OFA	NAv
Salt River Project	Navajo 2	T	CE	800	C	OFA	NAv
	Unit 1	Tu	RS	380	C	NBD,OFA	78
	Unit 2	Tu	RS	380	C	NBD,OFA	79
San Diego Gas & Electric	Encina 5	W	NAv	300	O	OFA	79
South Carolina Public Service Authority	Georgetown 2	Tu	RS	280	C	NBD,OFA	77
South Mississippi Electric Power Association	Morrow 1	Tu	RS	180	C	NBD,OFA	78
	Morrow 2	Tu	RS	180	C	NBD,OFA	78
Southern Indiana Gas & Electric	A. B. Brown	HO	BW	250	C	NBD	NAv
Southwestern Electric Power	Welsh 1	HO	BW	550	C	NBD	77
	Flint Creek	HO	BW	550	C	NBD	78
Springfield, City of	Southwest	Tu	RS	202	C	NBD	76
Tallahassee, City of (Florida)	Hopkins 2	W	BW	238	G,O	OFA,FGR	77
Tampa Electric Company (Florida)	Big Bend 3	Tu	RS	450	C	NBD,FGR	76
Texas Power & Light Company	Twin Oak 1	T	CE	750	L	OFA	82
Texas Utilities Public Service	Monticello 3	HO	BW	775	C	NBD	77
	Forest Grove 1	HO	BW	775	C	NBD	80
Utah Power and Light	Naughton 4	HO	BW	450	C	NBD	81
	Naughton 5	HO	BW	450	C	NBD	83

TABLE VIII. (Concluded)

Utility	Plant Name	Unit Type	Manu-facturer	Rated Output MW	Fuel	NO_x Control	Year Online
Utah Power and Light	Huntington Canyon 2	T	CE	400	C	OFA	77
Wisconsin Electric Power Coop.	Pleasant Prairie 1	Tu	RS	616	C	NBD	79
Wisconsin Power and Light	Columbia 1	T	CE	520	C	OFA	77
Wisconsin Public Service Corporation	Weston 3	T	CE	322	C	OFA	82

Unit Type

HO - Horizontally opposed
T - Tangentially fired
Tu - Turbo-fired
W - Single wall fired

NO_x Controls

BOOS - Burners out of service
FGR - Flue gas recirculation
NBD - New burner or furnace design
OFA - Overfire air
RAP - Reduced air preheat

Manufacturer

CE - Combustion Engineering, Inc.
BW - Babcock & Wilcox Co.
FW - Foster Wheeler Energy Corp.
RS - Riley Stoker Corp.

Fuel

C - Coal
G - Gas
L - Lignite
O - Oil

Others

NAv - Not available

FIELD TESTING OF UTILITY BOILERS AND GAS TURBINES FOR EMISSION REDUCTION

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ABSTRACT

The U. S. Environmental Protection Agency has sponsored a series of field test programs by Exxon Research and Engineering Company over the past eight years to determine the effect of combustion modification techniques on combustion related emissions, with emphasis on oxides of nitrogen (NO_x). The combustion modifications found to be effective in earlier programs in gas and oil fired utility plants were tried and also found to be effective in the more complicated pulverized coal fired utility boilers in later programs. These tests have shown that a combination of staged combustion and low excess air firing is a cost-effective means of controlling NO_x emissions in gas, oil, and coal-fired utility boilers. NO_x reductions averaging 40 percent have been achieved in pulverized coal-fired utility boilers in short term tests without significant adverse side effects on other emissions, boiler efficiency, boiler slagging and fouling. The long term effect of staged combustion on furnace tubewall corrosion rates is unresolved, but current and planned EPA sponsored tests should resolve this question and determine where corrective measures are needed.

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INTRODUCTION

Since 1970, Exxon Research and Engineering Company (ER&E) has been conducting field studies under EPA sponsorship on the application of combustion modification techniques to control pollutant emissions from utility boilers. The emphasis in these studies has been on controlling NO_x emissions without causing adverse side-effects.

Under EPA Contract No. CPA 70-90 (1), significant reductions of NO_x were achieved for gas and oil-fired boilers using combustion modification techniques in field testing of limited duration, without attempting to optimize the technology. The principal modifications investigated consisted of minimizing excess air, staged introduction of the combustion air, flue gas recirculation, varying boiler load, and varying air preheat temperature. Also, as part of this study, it was possible to achieve significant reductions in NO_x emissions for two of the seven coal-fired boilers tested, through the combination of low excess air with staged firing.

Because of the difficulty of controlling NO_x emissions from coal-fired boilers, in the subsequent EPA-sponsored ER&E study (Contract No. 68-02-0227) (2) the emphasis shifted to a more detailed investigation of emission control for coal-fired utility boilers, again in cooperation with boiler owner-operators and manufacturers. These field studies, on twelve coal-fired units representative of the current design practices of the major U.S. boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley Stoker), have produced very promising results. It was possible to achieve reductions in NO_x emissions ranging between about 30% and 50%, without apparent adverse side-effects. In addition to gaseous emissions measurements, the studies included particulated mass loading and unburned combustible measurements, accelerated furnace corrosion rate probing, determination of boiler efficiency, and observations on changes in boiler operability which particular attention to slagging, fouling, and flame problems.

Based on the encouraging results of the above work, the Environmental Protection Agency and the Electric Power Research Institute decided to jointly fund the present ER&E field study. The scope of the work was broadened to determine the effects of combustion modification techniques on the control of pollutant emissions and on the performance of fossil fuel fired power generation equipment. In this field program, the combustion equipment selected for study included coal-fired, mixed-fuel fired and waste fuel-fired boilers to be studied, in addition to short-term tests on stationary gas turbine and I.C. engine equipment. The principal continuing emphasis in this work remained on coal-fired utility boilers. All but one of the coal-fired boilers tested in this study had dry-bottom furnaces.

In the field studies detailed in this report, the combustion equipment selected was tested in cooperation with the owner-operators and the manufacturers. The effectiveness of equipment modifications designed to provide NO_x emission control, such as coal-fired boilers constructed with overfire air ports, and the use of low NO_x emitting improved burner design were explored. Potential adverse side-effects of combustion modifications were studied in more detail than previously. Thus in addition to the gaseous emission measurements (including pollutants, stable combustion products and unburned combustibles), particulate mass and size distribution measurements were made under both normal and low NO_x modes of boiler operation.

As in the earlier field studies, the effect of combustion modifications on boiler efficiency and operability was determined. Special attention was paid to the demonstration of potential furnace fireside tube wall corrosion problems that may result from staged firing with coal, i.e., with parts of the boiler operated under fuel rich, reducing conditions. For this purpose, 300-hour corrosion probe runs with air-cooled coupons were made under both low NO_x and baseline firing conditions in the boilers studied. corrosion probe runs of 30, 300 and up to 1000 hours were also made during a special long term corrosion test on one boiler included in this program to obtain information on the effect of corrosion with time.

FIELD STUDY PLANNING AND PROCEDURES

This section summarizes the boiler selection criteria, cooperative arrangements made with boiler manufacturers and operators, the test program strategies used, and the specific test procedures employed.

Test Program Design

The criteria recommended for the selection of coal fired utility boilers were classified into five groups: (1) boiler design factors, (2) boiler operating flexibility, (3) boiler measurement and control capability, (4) utility management's willingness to participate in research programs, and (5) logistic and scheduling considerations.

Boilers representing the current design practices of the U.S. utility boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley Stoker) were selected. Boiler size (150 MW or larger), type of firing (wall, tangential, turbofurnace and cyclone) furnace loading, burner configuration (size, number and spacing), draft system (balanced and pressurized), and furnace bottom design (wet or dry bottom) were all taken into account.

Earlier ER&E field test programs with coal (1,3) on one tangentially fired and one wall fired utility boiler have established that the combination of staged combustion with low excess air could lead potentially to the largest reductions in NO_x emissions. Although well researched for gas and oil fired installations, there was no report in the literature of the application of such combustion modifications to coal fired utility boilers for NO_x control. Because of this early indication of significant NO_x reduction potential, subsequent ER&E field programs have emphasized the above approaches (2,4).

As discussed before, the boiler units to be tested were selected on the basis of criteria established for this purpose. Testing the applicability of combustion modifications, two principal goals were set: (1) establishing sufficient information by boiler and fuel characteristics so that the knowledge gained could be applied to other existing installations, and (2) generalizing the information adequately to help guide the design of new installations for meeting the New Source Performance Standard (NSPS) of 301 ng/J (0.7 lb/10^6 Btu) heat input for NO_x emissions.

The test program evolved through several stages -- initially, short term gaseous emission measurements were made to assess the applicability of combustion modifications for NO_x control. This was followed by field test programs tailored to individual boilers characteristic of current design practices, where a series of short term (Phase I) gaseous emission measurements were made. These were followed by a 1-2 day (Phase II) period under low NO_x combustion modification conditions to check for potential operating problems and to make any required adjustments. Finally, 300-hour sustained runs were conducted under both low NO_x and baseline boiler operating conditions to allow short-term fireside tube corrosion tests to be made with corrosion coupons, and also to determine the effect of combustion modifications on boiler efficiency, operability, particulate mass loading and size distribution, and SO_2/SO_3 concentration in the flue gas. (For the purposes of this study, low NO_x operation denotes modified firing of the boiler resulting in the lowest NO_x levels without apparent short-term side effects. Baseline operation is at or near full load conditions corresponding to low NO_x operation, but with conventional firing.)

With a sufficient data base in hand on combustion modifications for coal fired utility boilers of different design and size characteristics, additional units were selected for testing based on special features. The latter included units designed and built by their manufacturers to meet the NSPS for NO_x, and specially modified boilers that provided the flexibility for testing combustion modifications and new low NO_x burner designs.

Statistical principles provided practical guidance in planning the Phase I test programs; e.g., how many, and which test runs to conduct, as well as the proper sequence in which they should be run. These procedures allow valid conclusions to be drawn from analysis of data on only a small fraction of the total possible number of different test runs that could be made in principle, resulting in increased productivity of the research work.

Statistical principles were also used extensively in the analysis of emission data recorded from each test run. For example, least-squares regression analysis was used to obtain valid estimates of the relationship between NO_x emission levels and operating variables, such as excess air level. These techniques provide objective, uniform methods of analysis that can be easily verified, provide the basis for efficient assessment of outlier data, and limit the risk of drawing false conclusions.

Gaseous Sampling and Analysis

The mobile sampling and analytical system used in this study to obtain reliable gaseous emission data from field tests was described elsewhere in detail (1,4). The gaseous species analyzed are NO, NO_2, O_2, CO_2, CO, SO_2 and hydrocarbons. The instruments contained in the ER&E sampling and analytical van were also described in detail (1,4) according to manufacturer, operating technique employed, and measurement range capabilities.

A major consideration in obtaining reliable gaseous emission data is to insure that the sample gas is virtually moisture free. Moisture in the sample gas can influence the readings obtained by some of the analytical monitoring insturmentation. For example, moisture is an unwanted interference with NO, CO_2 and CO nondispersive infrared analyzers. This problem is avoided effectively in the sampling system used by passing the sample gases through a refrigerated water trap coil. Recently, permeation-type drying tubes (Permatubes supplied by Perma Pure, Inc., Oceanport, N.J.) have become available for removing moisture in gas sampling systems without changing the concentration of other gaseous species. For this reason, Permatube driers were adapted to the sampling train as an addition to the refrigerated traps to insure a maximum drying capability for the gaseous emission sampling system. This system has proven to be effective in obtaining dry sample gases.

In the ER&E sampling-analytical system, gaseous samples are taken from zones of "equal areas" in the flue gas ducts. At least two probes are installed in each flue gas duct, or a minimum of four are used when there is only one large flue gas duct on the boiler. Each of the probes consists of three stainless steel sampling tubes (short, medium and long) reaching to the mid-point of zones of equal area through the depth of the duct. Thus, a minimum of six sampling points per duct, or 12 per boiler, are provided, assuring that representative gas samples are obtained. The soundness of this approach to gaseous emission sampling was verified by the results of another EPA supported ER&E study on the stratification of gaseous species in boiler ducts (5).

A complete range of calibration gas cylinders in appropriate concentrations with N_2 purge and zero gas for each analyzer are installed in the system. The instruments are calibrated daily before each test, and also in-between tests, if necessary, to assure reliable and accurate results.

Particulate and SO_x Sampling

To control NO_x emissions, combustion modification techniques are used at less intense combustion conditions than those corresponding to conventional firing methods. Adjusting secondary air dampers, lowering excess air, or staging the combustion pattern may increase unburned combustibles. Beyond the issue of combustibles (soot particulates and unburned carbon), modifications to the combustion process for NO_x emission control may also affect the quantity, size distribution and composition of the particulate matter emitted from the boiler.

To obtain information on the effect of combustion modifications on particulate emissions, the field studies included the measurement of particulate mass loading and fly ash particle size distribution upstream of the particulate collector device of pulverized coal fired utility boilers. Measurements of total mass loading and particle size distribution were made under baseline and optimized low NO_x operating conditions to determine the extent of adverse effects of staged firing and other NO_x

emission reduction techniques. Flyash was analyzed for unburned carbon content for use in these comparisons and in boiler efficiency calculations discussed later.

Two Joy Manufacturing Company Method 5 trains and two Acurex High Volume EPA type particulate sampling trains designed according to EPA Method No. 5 (6) were used to obtain particulate mass loading data. These trains were modified to incorporate Brink multi-stage cascade impactors in the heated sampling box for the determination of particle size distribution. This arrangement permits particle size distribution determinations on the outside of the boiler duct under isokinetic sampling conditions.

Wet chemical analyses for the determination of sulfur dioxide and sulfur trioxide content of boiler flue gases were made using an Exxon Research and Engineering Company modification of EPA Method No. 6. Flue gas samples were extracted from the boiler ducts through a heated probe and passed through a series of two absorbers, the first one containing isopropanol to absorb the sulfur trioxide and the second one a hydrogen peroxide solution in isopropanol to absorb the sulfur dioxide. The amounts absorbed were determined titrimetrically using barium perchlorate as the titrant and thorin as the indicator.

Furnace Fireside Tube Wall Corrosion Probe Measurements

Under certain conditions, pulverized coal fired boilers are subject to corrosion of the furnace tubes. Normal corrosion occurs in oxidizing atmospheres due to the corrosive effect of iron alkali sulfate attack on the tube metal surface. However, under fuel-rich reducing conditions, corrosion of the furnace tubes may be accelerated (particularly with high sulfur, high iron content coals) due to increased slagging on the tube surface and penetration of iron sulfide into metal surfaces. Under normal firing conditions this type of corrosion is most likely to occur in areas where a localized reducing invironment might exist adjacent to the midpoint of furnace sidewalls near burner elevations where flame impingement might occur. To counteract such effects normal boiler operating practice is to increase the excess air level so that an oxidizing atmosphere prevails at these locations, and to increase the fineness of pulverization, so that the oxidation of the pyrites in the coal is completed before these species can come into contact with the furnace wall tube surface. For new boilers, an improved design feature consists of increasing the separation between the burners and the sidewalls, thus minimizing potential flame impingement problems.

The most effective combustion modifications used at present for controlling NO_x emissions from coal fired boilers are staged combustion and low excess air firing; i.e., conditions that are potentially conducive to furnace tube wall corrosion. In the early stages of these field programs, the approach used for measuring corrosion rates was to expose corrosion coupons installed on the end of probes. The probes were inserted into available openings located near "vulnerable" areas of the furnace under both baseline and low NO_x firing conditions. Coupons were fabricated of SA 192 carbon steel, the same material as that currently used for furnace wall tubes. Exposure of the coupons for 300 hours at elevated temperatures of 742 K (875°F) [higher than normal furnace tube wall surface temperature of about 589 K (600°F)] was chosen in order to deliberately accelerate corrosion so that measurable values could be obtained. Coupons were also mildly pickled to remove the existing oxide coating prior to exposure to eliminate potential differences caused by surface conditions. The conclusion of these earlier corrosion probing tests was that no major differences in corrosion rates could be found between coupons exposed to low NO_x firing conditions and coupons exposed under normal boiler operating conditions. Coupon corrosion rates were, however, considerably higher under both baseline and low NO_x conditions than those corresponding to normal furnace tube corrosion rates because of the accelerated nature of these corrosion probing tests.

In subsequent corrosion coupon tests, the acid pickling feature was eliminated. Instead, the coupons were dipped in acetone and air dried prior to weighing to remove any oil deposited during machining. Also, coupon temperatures were reduced to simulate actual furnace tube wall conditions, at about 589 K (600°F), and three coupons per probe were used, instead of two, to obtain more information per test. The design of the corrosion probes was based on information supplied by Combustion Engineering, with appropriate modifications for this work. Essentially, the design consists of a "pipe within a pipe," where the cooling air from the plant air supply is admitted to the ring-shaped coupons exposed to furnace atmospheres at one end of the probe, through a 19 mm (3/4-inch) stainless steel tube roughly centered inside of the coupons. The amount of cooling air is automatically controlled to maintain the desired set-point temperature of 603-672 K (625-750°F) for the coupons. The cooling air supply tube is axially adjustable with respect to the corrosion coupons, so that temperatures of coupons may be balanced. The cooling air travels backwards and discharges outside the furnace.

Boiler Efficiency

The application of staged combustion for NO_x emission control is based on fuel rich operation of a number of burners. This results in less intense combustion conditions which may increase carbon burnout problems. Thus, because this mode of boiler operation may increase the amount of unburned combustibles, there may be an adverse impact on boiler efficiency. However, potential efficiency losses may be compensated by the increase in efficiency resulting from reduced stack losses if low excess air firing is employed. To determine the effect on boiler efficiency of combustion modification techniques applied for NO_x control, particulate emission measurements were run for each boiler under baseline and low NO_x operating conditions and the fly ash samples were analyzed for unburned carbon. Boiler efficiency was then calculated using the ASME Abbreviated Efficiency Test based on the heat loss method, and the results were compared to evaluate the effects of low NO_x firing on efficiency.

NO_x Tests in Gas Turbines

NO_x emissions were measured in three gas turbines during the course of the current program to establish emission levels with gas and oil fuels and to investigate the potential for NO_x reduction. All turbines tested were General Electric MS7001B models having a capacity rating of 50 MW. The first turbine tested was Potomac Electric Power Company's Morgantown GT No. 3 turbine firing distillate fuel oil with no provisions for water injection. Houston Lighting and Power Company's LH Wharton GT No. 42 and No. 43 were the second and third turbines tested. Both turbines have water injection capabilities for NO_x emission control. Turbine No. 42 was tested while firing distillate fuel oil and No. 43 with natural gas.

Gas turbines are much less flexible than boilers to combustion modification. Combustion air fuel ratios can be changed within limits but making the required changes would have been a time consuming operation beyond the scope of this program. As a consequence, investigations of NO_x emission levels from gas turbines in this program were confined to the effects of gross load and variations in water injection rates with the different fuels tested.

RESULTS AND DISCUSSION

Results of the initial EPA sponsored program covering field test investigations on twelve coal fired utility boilers employing combustion modifications to reduce NO_x emissions (2) were reported in Report No. EPA-650/2-74-066 dated June 1974. Tests on nine additional coal fired boilers were conducted under the current, ongoing contract sponsored by EPA. Testing of a tenth boiler, also included in the current contract, covered extensive long and short term testing of corrosion and gaseous emissions on the No. 7 unit at the Crist station of the Gulf Power Company, a 500 MW, horizontally opposed fired, Foster Wheeler boiler. Results of the long term corrosion tests are not available at the time of writing this paper.

Table 1 summarizes results of the tests on the nine boilers, mentioned above, including design and operating features, numbers of short-term tests conducted, and emission levels determined for baseline and optimum low NO_x firing conditions for each boiler tested. It may be noted in Table 1 that uncontrolled NO_x emissions in the nine boilers ranged from 341 to a maximum of 1383 ppm with only three boilers meeting the New Source Performance Standard (NSPS) of 0.7 lbs $NO_x/10^6$ BTU (525 ppm) and two of these, Navajo No. 2 and Comanche No. 1, were designed with overfire airports for NO_x control. Also note that optimum NO_x emissions, achieved through combustion modification, successfully reduced emissions below the present NSPS in all but one case (Mercer No. 1). Average NO_x reductions were 38%, ranging from 12 to 62%, almost precisely the same as achieved in testing 12 boilers in the prior contract.

Table 2 contains a summary of the five wall-fired boilers tested. It may be seen that all of the wall-fired boilers under baseline operating conditions produced NO_x emissions exceeding the New Source Performance Standards for coal-fired boilers. However, the Gaston No. 1 unit, equipped with B & W's low NO_x burners, had emissions of 309 ppm NO_x under baseline conditions, well below the NSPS NO_x level. With modified combustion operation, four of these boilers could be operated within the NSPS limits. The exception, Mercer No. 1, a wet-bottom furnace with high heat release and limited operating flexibility, required a 20% load reduction in addition to combustion modifications to meet the standard. Also note that the average percent reduction in NO_x emissions for these boilers was 38 percent.

Tangentially fired boilers are summarized in Table 3. It can be seen that the three boilers equipped with overfire airports operating at full load, baseline operation with cooling air only through the airports, emitted NO_x below the NSPS level. Morgantown No. 1 (without airports) emitted NO_x slightly above this level when firing 100% coal. Modified firing using the overfire airports for NO_x control, however, reduced NO_x emissions to levels below NSPS requirements. NO_x emission reductions of 27 to 45% were achieved in these boilers for an overall average of 37%, essentially the same as for the wall-fired boilers.

Nitrogen Oxides Emissions

Details of the results obtained in these field studies are available through reports prepared for the EPA (2,3). To illustrate the type of emission reductions achieved in these investigations one tangentially fired boiler (Salt River Project, Navajo Boiler No. 2), and one wall (horizontally opposed) fired boiler (Southern Electric Generating Company, E. C. Gaston Boiler No. 1) retrofitted with low NO_x burners have been chosen for discussion.

Navajo Unit No. 2 is a twin furnace, 800 MWe, tangentially fired, Combustion Engineering boiler. The furnace has a volume of 13,182 m^3 (465,000 cu. ft.), width of 25.5 m (83 ft. 6-3/4 in.) and front to rear length of 12.45 m (40 ft. 10-1/4 in.). Maximum continuous steam flow is 2,450,000 kg/hr (5,400,000 lb/hr), at 814 K (1005 °F), with a reheat steam flow of 2,200,000 kg/hr (4,850,000 lb/hr) at 813 K (1003 °F). The normal fuel fired is Black Mesa sub-bituminous coal with a higher heating value of 24,950 kJ/kg (10,725 Btu/lb), containing 10.4% ash, 10.3% moisture, 38% volatile material and 41.4% carbon. At maximum continuous rating, 296,000 kg/hr (652,000 lb/hr) of coal is fired and design efficiency is 88.77%. Seven pulverizers feed 56 burners arranged to fire at seven different levels. Overfire tilting airports are located above the top row of burners.

Operating variables included in the experimental program were gross load, excess air level, burner tilt, and firing pattern.

Fig. 1 is a plot of NO_x emissions vs. percent oxygen for various staging patterns, including operation of the top level burners on air only. The least-squares line labelled S_7, corresponding to 100% overfire air (OFA), was drawn from other data for purposes of comparison. Short lines parallel to the S_7 line were drawn through the averaged data for S_4, S_5 and S_6 test runs. The lowest NO_x emissions resulted with the top tier of burners on air only (S_2) and cooling air through the overfire air registers. The beneficial effect of increasing overfire air register openings from 25% (S_4) to 50% (S_5) and then to 75% (S_6) is apparent from Fig. 1.

Fig. 2 illustrates the effect of changing overfire air register settings more directly. Only test runs conducted with approximately equal excess air levels (3.6 to 4.0% O_2) and burner tilts (+ 10° to + 15°) are shown on Fig. 2 so that the effect of overfire air damper settings on NO_x emission levels can be seen directly. Average NO_x levels decreased from 193 ng/J (330 ppm) to 186 ng/J (318 ppm), 170 ng/J (290 ppm), and 165 ng/J (283 ppm) as the overfire air damper openings were increased from 25% to 50%, 75% and 100%, respectively.

The effect of burner tilt on NO_x emissions with the overfire air dampers 100% open may be seen in Fig. 3. At the higher excess air levels at which boilers normally operate (4.5 to 5.0% O_2), burner tilt can have an appreciable effect on NO_x emissions as shown in Fig. 3. With combustion modifications and low excess air operation for NO_x control, however, it may be seen that emissions are relatively insensitive to burner tilt.

Because Boiler No. 1 at the Ernest C. Gaston Station of the Southern Electric Generating Company had been retrofitted with newly designed, low NO_x burners by its manufacturer, Babcock and Wilcox, this boiler was of special interest for testing in these studies. These dual register, compartmentalized windbox burners produce a limited turbulence, controlled diffusion flame designed to minimize the amount of fuel and air mixed at the burner to that necessary to obtain ignition and to sustain combustion of the fuel (7).

Gaston Boiler No. 1 and its sisten unit, Gaston No. 2, are 270 MWe, 18-burner, horizontally opposed, pulverized coal fired Babcock and Wilcox boilers. Two division walls divide each furnace into three equal compartments, each having six burners arranged three high in both the front and rear walls of the furnace. The furnace is 18.3 m (60 feet) wide, with a volume of 3950 m^3 (139,500 cubic feet) and a total wall area of 2391 m^2 (25,732 square feet). Six pulverizers, each with 16,300 kg (36,000 pounds) capacity, feed coal to three burners each as shown in Fig. 4. The maximum continuous rating of each boiler is 771,000 kg (1,700,000 pounds) of steam per hour. Steam temperature controls include flue gas recirculation into the hopper area of the furnace and spray attemperators for primary superheat and reheat.

Fig. 5 represents a plot of NO_x emissions vs. average percent stoichiometric air to the active burners. It may be noted that NO_x emissions in Boiler No. 2 (equipped with conventional burners) at full load of 270 MWe, averaged 346 ng/J (591 ppm) at 24% excess air. In comparison Boiler No. 1 when operated at full load of 270 MWe, averaged only 220 ng/J (377 ppm) at 24% excess air. Therefore, the new dual register burners used in Boiler No. 1 reduced NO_x emissions significantly; i.e., by 36% compared to conventional Babcock and Wilcox burners.

In Fig. 5, least-squares, linear regression lines were calculated from the data points representing normal firing (S_1) at 270 MWe, normal firing at 205 MWe, staged firing (S_2 - top mill burners on air only on front or rear wall) at 250 MWe and staged firing operation (S_3 - top mill burners of front and rear walls on air only) at 190 MWe.

From a full load, base level NO_x emission level of 220 ng/J (377 ppm) (124% stoichiometric air), low excess air operation reduced NO_x emissions from Boiler No. 1 by about 20% to 178 ng/J (305 ppm). Two staged firing patterns on air only (S_3). Low excess air, staged firing at 250 MWe reduced NO_x emissions to as low as 140 ng/J (240 ppm) with B mill burners on air only (S_2). Low excess air, staged firing at lower loads of 190 and 148 MWe reduced NO_x emissions to as low as 106 and 87 ng/J (182 and 148 ppm), respectively, with both E and B mill burners on air only (S_3). Analysis of secondary air register setting vs. NO_x shows that the lowest NO_x level was generally reached when the register setting was approximately 70% open, with both lower and higher settings producing higher NO_x levels.

PARTICULATE EMISSIONS

As mentioned previously, low NO_x combustion modifications may tend to increase burnout problems. Particulate mass loading could increase as a consequence of the increased carbon in the fly ash and precipitator collection efficiency could be adversely affected. Changes in particle size distribution as a result of low NO_x firing could also have a similar adverse effect on the efficiency of the gas cleaning device. In these studies low NO_x combustion modification effects on dust loading were investigated using an EPA Method 5 type sampling train incorporating a Brink cascade impactor for particle size determination. In the latter phase of the contract dust loading measurements were made with EPA's SASS train sampling system. Results of the analyses of the latter tests, however, are not available at this writing and will be presented later.

Comparison of typical particulate mass loading data obtained in this program using the EPA Method 5 sampling train may be made from the information tabulated in Table 4. Comparison of baseline with low NO_x operation in the table shows, in some cases, that particulate mass loading tends to increase with low NO_x firing, i.e., Gaston No. 1 and No. 2, and Navajo No. 2. The effect, however, appears to be minor. In the other boilers, particulate emissions are either roughly the same or lower with low NO_x firing. It was concluded from these and other data obtained in prior program that changes in particulate mass loading due to combustion modifications for low NO_x firing are not significant.

The potential effect of low NO_x operation on changes in flue gas particle size distribution was investigated in this program using a Brink Cascade impactor. As indicated above, precipitator collection efficiency could be impaired if low NO_x operation resulted in a larger proportion of fine material being produced. Table 5 tabulates typical particle size distribution data obtained in this program and indicates that particle distribution under low NO_x conditions is essentially the same as for baseline operation. It is concluded, therefore, that there are no significant differences in particle size distribution under low NO_x firing.

BOILER PERFORMANCE

The potential side effect of low NO_x operation on boiler efficiency was also investigated in these field studies. Typical results of boiler efficiencies calculated from the data obtained during these tests, using the ASME Abbreviated Efficiency Test Method, are tabulated in Table 6. The data in Table 6 shows that in only two cases (E. C. Gaston No. 1 and Mercer No. 2) are the carbon losses (unburned combustibles) higher for low NO_x firing. Boiler efficiency consequently would be expected to be adversely affected. However, calculated boiler efficiencies for low NO_x operation show no appreciable or significant changes. Debits in efficiency due to incomplete combustion are offset by increases in efficiency resulting from low excess air operation. It is concluded that no significant changes in efficiency occur when operating at optimum NO_x emission levels.

SULFUR OXIDES EMISSIONS

Flue gas samples taken from the ducts at the air heater inlet were analyzed wet chemically for SO_2/SO_3 content using an Exxon Research modification of EPA Method 6. Table 7 provides illustrative data on typical sulfur oxide emissions measured. A comparison of calculated SO_x values, based on 100 percent conversion, with measured values shows that calculated values are higher. This is as expected since it is well known that a portion of the sulfur remains in the ash in pulverized coal fired boilers. In a typical dry bottom boiler, 15 to 25% of the ash remains in the furnace and is extracted as bottom ash. The remaining 80 to 85% is carried out with the flue gas where better than 98 percent in most units is collected in the electrostatic precipitator. A portion of the total sulfur remains in these accumulations to decrease the amount emitted as SO_2 or SO_3 in the flue gases.

Emissions of SO_3 are essentially the same for baseline and low NO_x

firing, ranging from 5 to 16 ppm. These values are within the anticipated range of 5 percent of total flue gas SO_x.

FURNACE TUBE CORROSION

Staging the firing pattern to control NO_x emissions results in combustion at substoichiometric conditions in the first stage, creating a reducing atmosphere in the lower furnace areas. Potentially this type of operation may result in corrosion of the furnace waterwall tubes due to iron sulfide attack. Earlier attempts to quantify this potential side effect were limited to exposure of corrosion probes for 300 hours under accelerated conditions to obtain "measurable wear". Examples of the typical high corrosion rates obtained are shown in Table 8 for the Harllee Branch No. 4 boiler of Georgia Power Company. The wide range of corrosion rates measured is typical of the accelerated tests.

In the current study, pickling of the corrosion coupons was eliminated and exposure temperatures were reduced to furnace tube metal temperatures in order to approximate actual conditions. This resulted in lower corrosion rates as shown in Table 8 for the Widows Creek and E. C. Gaston boilers, ranging from 7 to 15 mils per year. However, these results are still significantly higher than the 2 to 3 mils per year anticipated for actual furnace tubes under normal firing conditions. Even though somewhat higher corrosion rates are indicated for low NO_x vs. baseline firing, the scatter in the data was such that these differences could not be established as statistically significant.

The effects of corrosion rates with time were explored in tests on the No. 7 boiler at the Crist Station of Gulf Power Company. Probes were exposed under baseline and low NO_x firing conditions for approximately 30, 300, 600, 740 and 1000 hours. Data obtained are plotted in Fig. 6 with curves drawn through points of average corrosion rates determined for the test. As seen in Figure 6 corrosion decreases with time, which is typical of most high temperature corrosion mechanisms. Initial corrosion rates are very high with considerable scatter.

Exposure times above 600 hours yield low corrosion rates very closely equal to the steady state corrosion rate observed at 1000 hour exposure time. Fig. 6 shows that corrosion rates obtained with probes under low NO_x conditions in these tests are no higher than for baseline operation.

Long term, steady state corrosion rates measured with corrosion probes of 9 to 10 mils per year are still significantly higher than the 2-3 mils/year experienced with actual furnace tubes under normal firing conditions. It is difficult to correlate the corrosion probe measurements to that experienced in furnace tubes. A long term corrosion test conducted during the current program sponsored by EPA, was completed recently in cooperation with Gulf Power Company and Foster Wheeler. Corrosion rates were measured by three means: corrosion probes (as described above), ultrasonic mapping of tubewall thickness at six furnace elevations, and exposure of 8 furnace tube test panels in corrosion prone areas of the furnace. The results of the long term corrosion test at Crist No. 7 boiler will be compared to those of the corrosion probe tests.

Currently, Exxon Research has initiated under contract to EPA long-term corrosion tests on four coal fired boilers. These tests will be discussed in further detail in the next presentation.

Gas Turbine Emissions

As mentioned previously, three gas turbines were tested in the current program for emission levels and potential NO_x reduction. Emission levels as a function of gross load were investigated in all three turbines and the effects of variation in water injection rate were fully explored in the gas fired and oil fired turbines equipped with water injection facilities

Table 9 summarize the pertinent data obtained during these tests. Baseline (uncontrolled) NO_x emissions in the two oil fired turbines (Morgantown No. 3 and Wharton No. 42) appear to be essentially the same at all loads. As expected, NO_x emissions from the natural gas fired turbine (Wharton No. 43) are only 55 to 60% of those in the oil fired units. As shown in Table 9, both gross load and water injection rate have a significant effect on NO_x, CO and HC emissions.

The effect of gross load and water injection rate may be observed more clearly in Figure 7. At full to peak load, baseline NO_x emission for the Wharton No. 42 oil fired turbine is 214 ng/J (127 ppm-15% O_2, dry basis). As the top line on Figure 7 illustrates NO_x emissions decreased linearly with decreasing load. Reducing load from 51 MW to 20 MW reduced NO_x emissions by 43% (127 to 72 ppm). However, water injection had a larger influence on NO_x emissions than load reduction did. At 55.5 MW, 2.3% water injection (based on combustion air) reduced NO_x emissions to 22 ng/J (13 ppm-15% O_2, dry basis) or about a 90% reduction over baseline emissions. Similar effects may be observed in Figure 8 for the natural gas fired Wharton No. 43 gas turbine.

CONCLUSIONS

The results of this field studies of combustion modifications on coal fired utility boilers lead to the following conclusions:

1. Tangentially fired utility boilers operate under baseline conditions with NO_x emissions at or near the NSPS level of 301 ng/kj (0.7 lb/10^6 Btu). Wall fired units are higher NO_x emitters under baseline conditions.

2. Combustion modifications can significantly reduce NO_x emissions for all types of firing by 40%, albeit with potential loss in boiler capacity if no special features are incorporated into the boiler system.

3. With special features such as overfire air ports or low NO_x burners as an integral part of the boiler, all types of firing systems appear to be capable of meeting (or operating below) the NSPS NO_x level.

4. Low excess air, staged firing mode of operation is at present the most effective combination of furnace combustion modifications for controlling NO_x emissions from coal fired utility boilers. The optimum firing pattern generally established is the operation of the top burners on air only. This is consistent with the favored use of built-in overfire air ports.

5. Low NO_x burners appear to produce significant reductions in NO_x emissions from coal fired utility boilers. The effectiveness of operating low NO_x burners with furnace combustion modifications appears promising, but requires further investigation.

6. The side effects of combustion modifications used for NO_x emission control are not significant, with the possible exception of furnace tubewall fireside corrosion. Long term tests are required to assess the effect of staged firing with coal on fireside corrosion. The effect of combustion modification on slagging varies from coal to coal and may

limit the extent to which combustion modification can be used.

7. NO_x emissions in large gas turbines firing either natural gas or light fuel oil can be reduced by 80 to 90 percent with water injection. Natural gas firing produces NO_x emissions about 40 percent lower than with distillate (light) fuel oil fired in the same size turbine.

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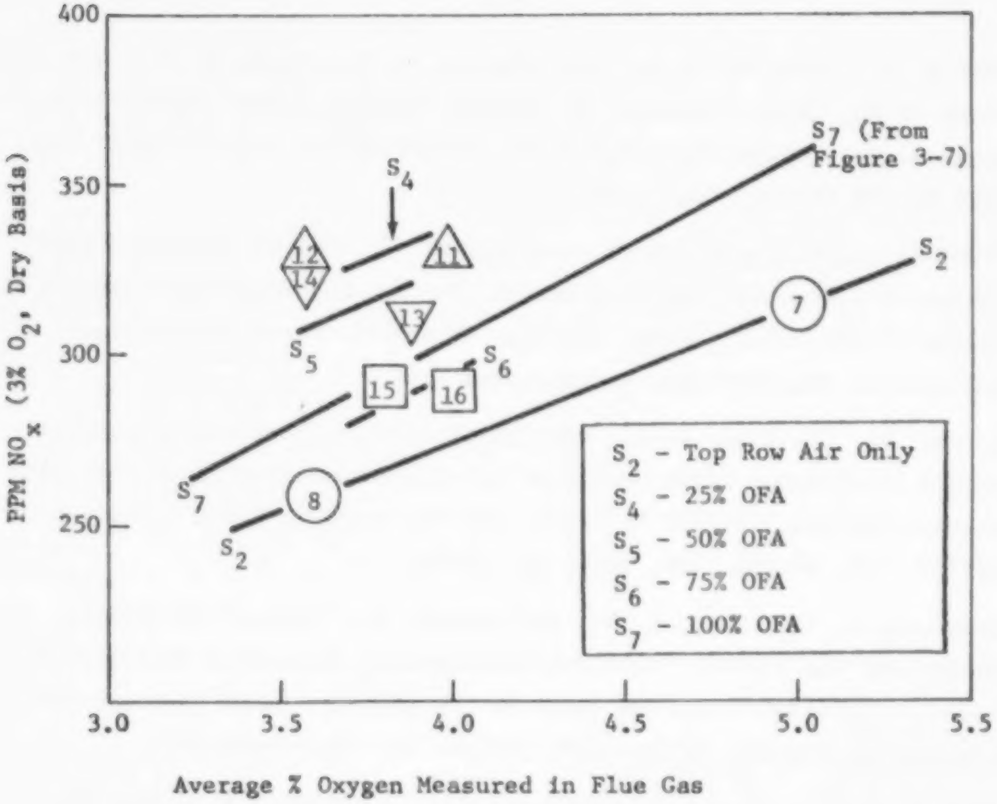

Figure 1. PPM NO_x Emissions Vs. % Oxygen for Navajo No. 2 Unit Under Staged Firing Operation

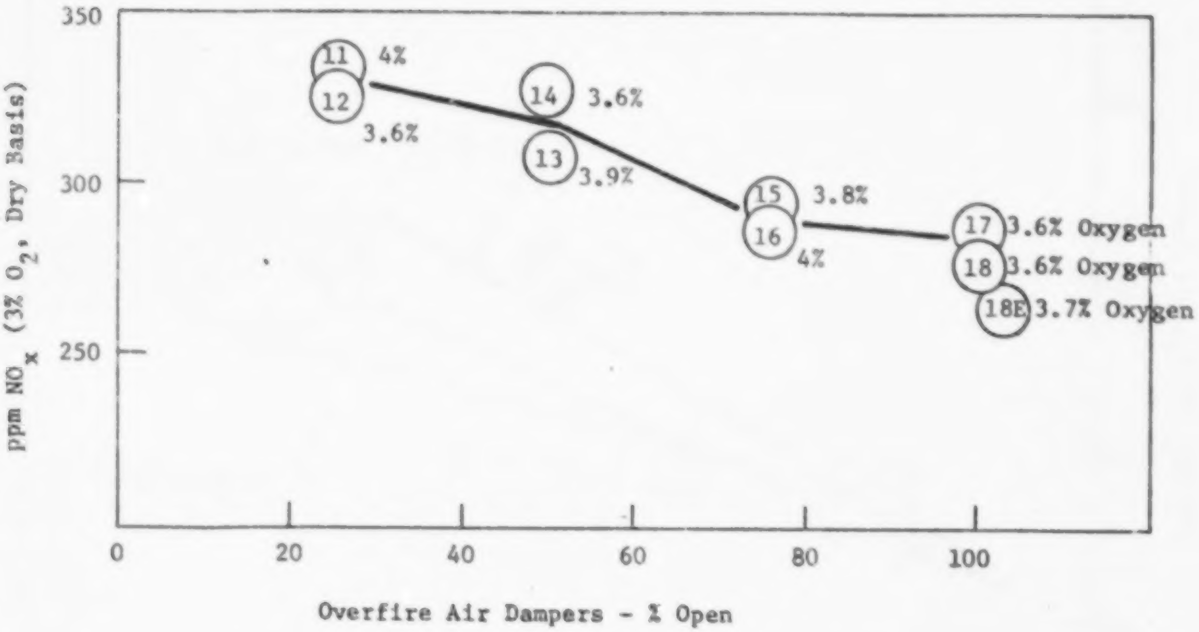

Figure 2. Effect of Opening Overfire Air Dampers on NO_x Emissions From Navajo No. 2 Unit at Full Load

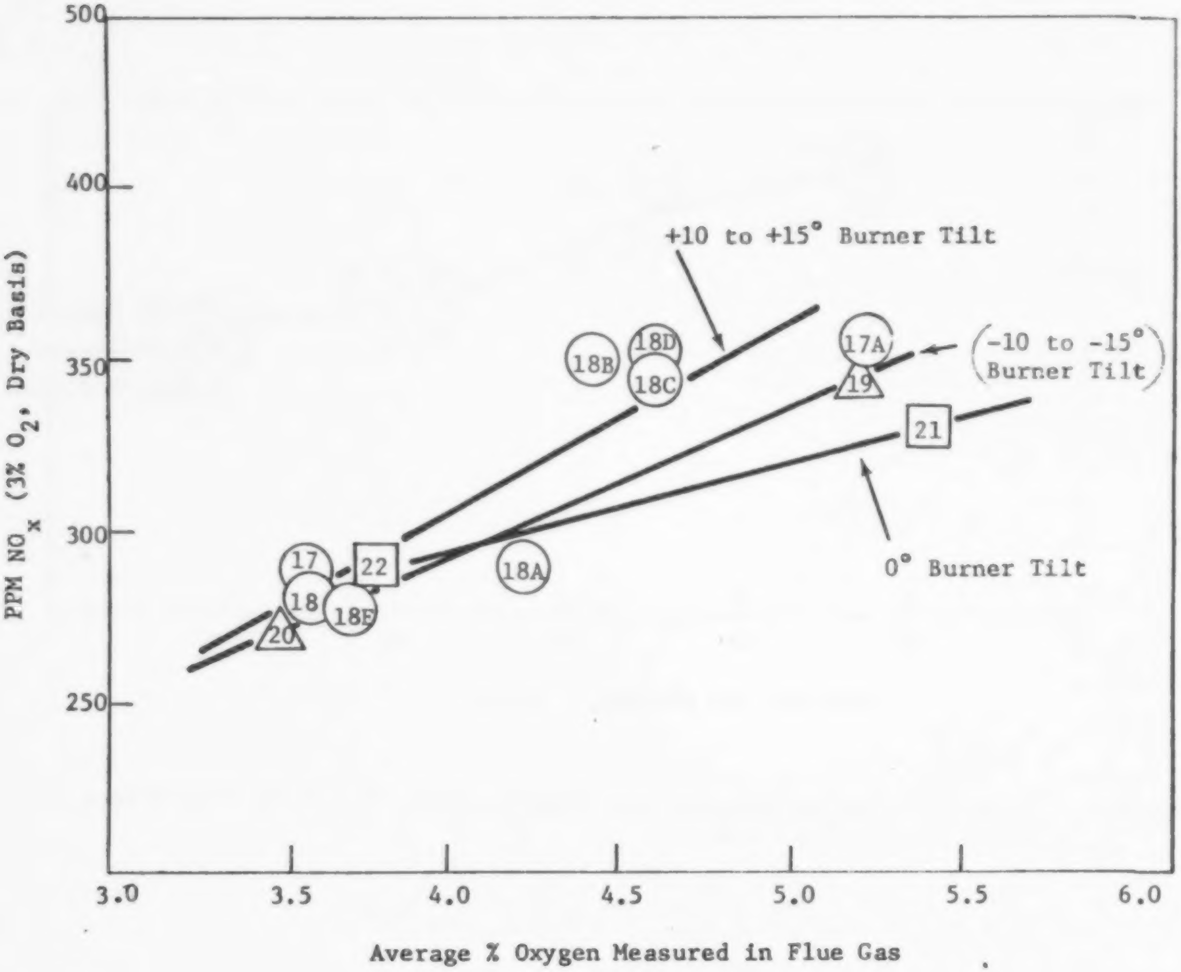

Figure 3. PPM NO_x Emissions vs. % Oxygen for Navajo No. 2 Unit Operating With Overfire Air Dampers 100% Open

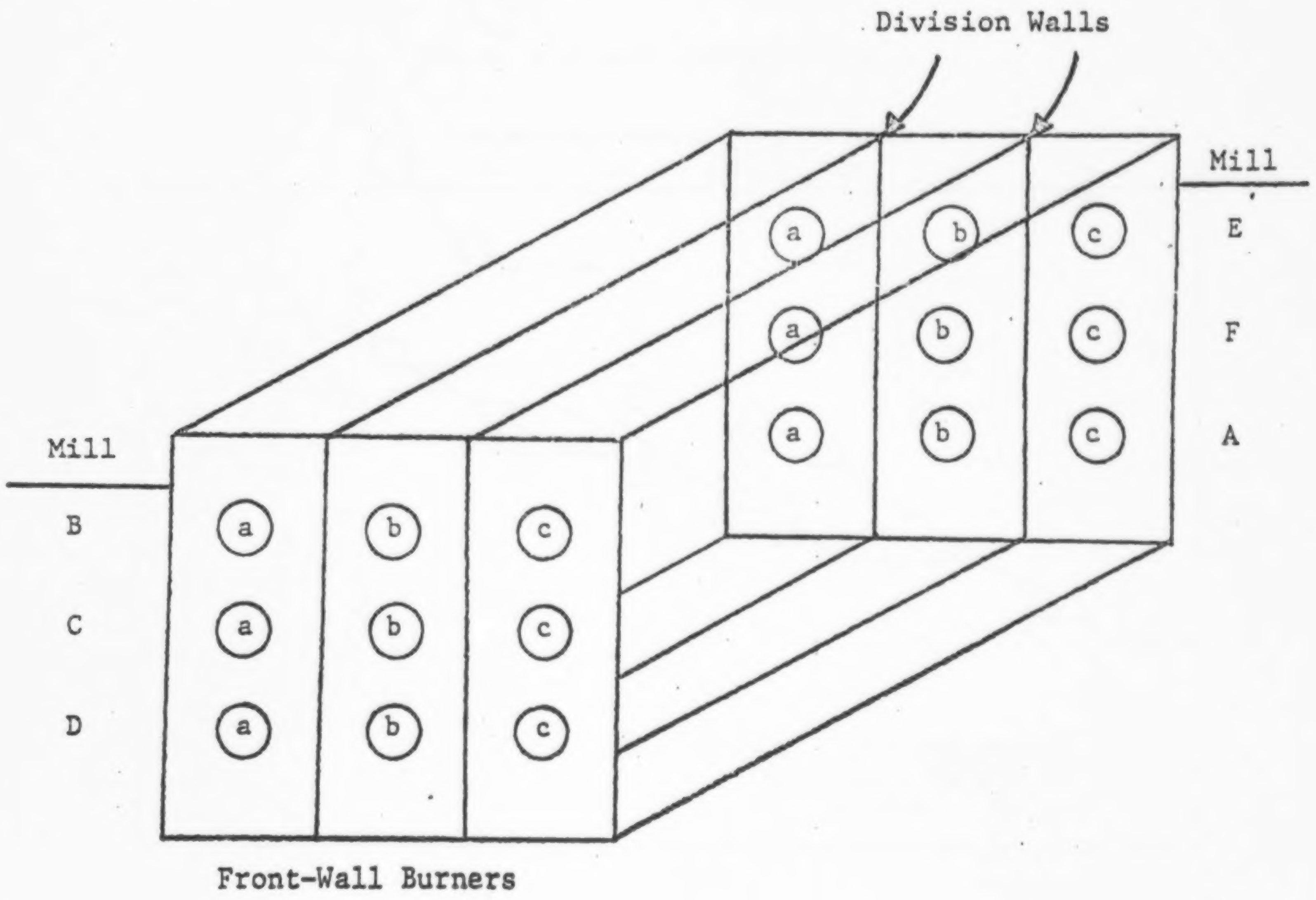
Division Walls
Mill
E
F
A
Mill
B
C
D
a
b
c
Front-Wall Burners

Figure 4. E. C. Gaston - Boiler No. 1

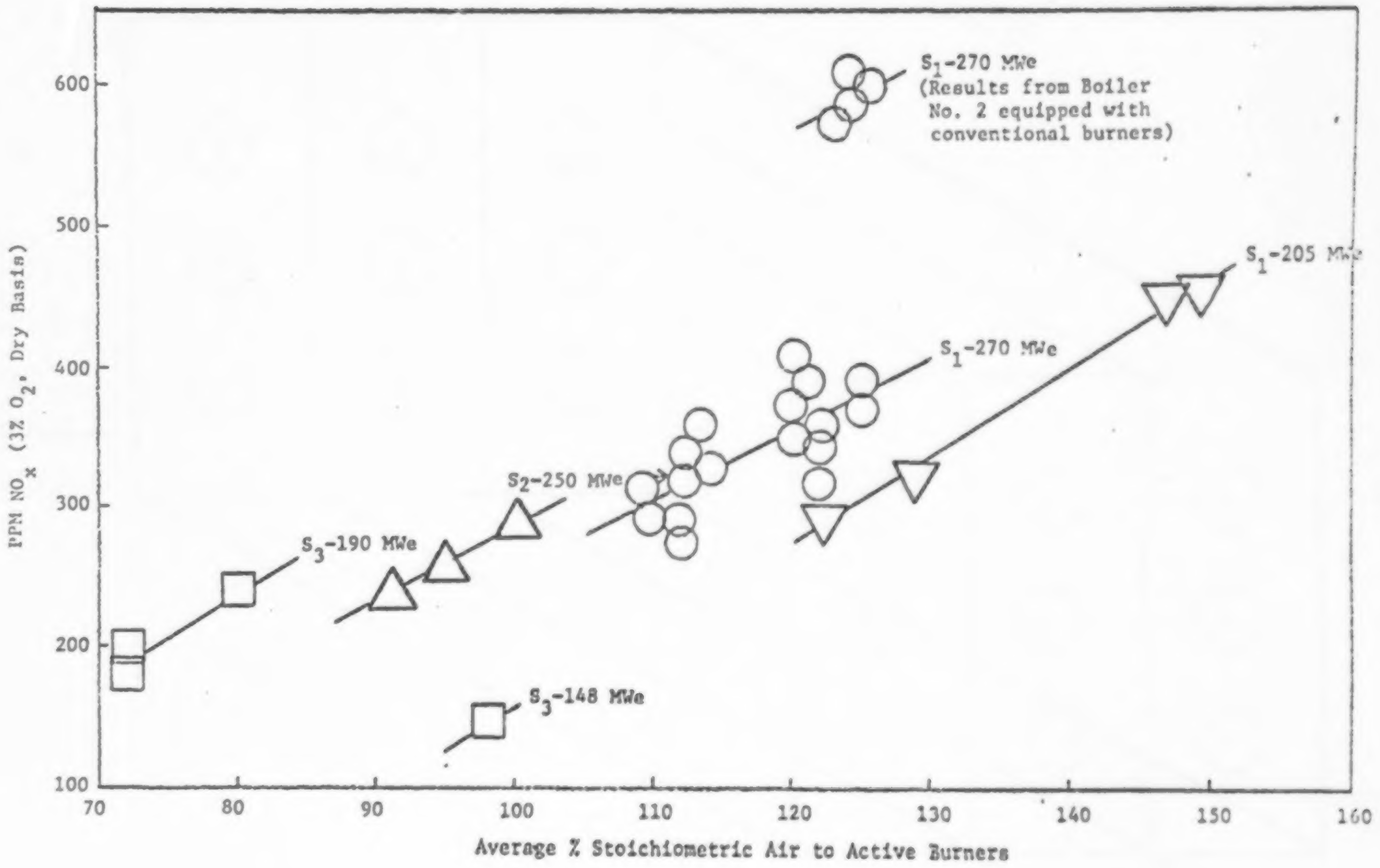

Figure 5. E. C. Gaston - Boilers No. 1 & No. 2

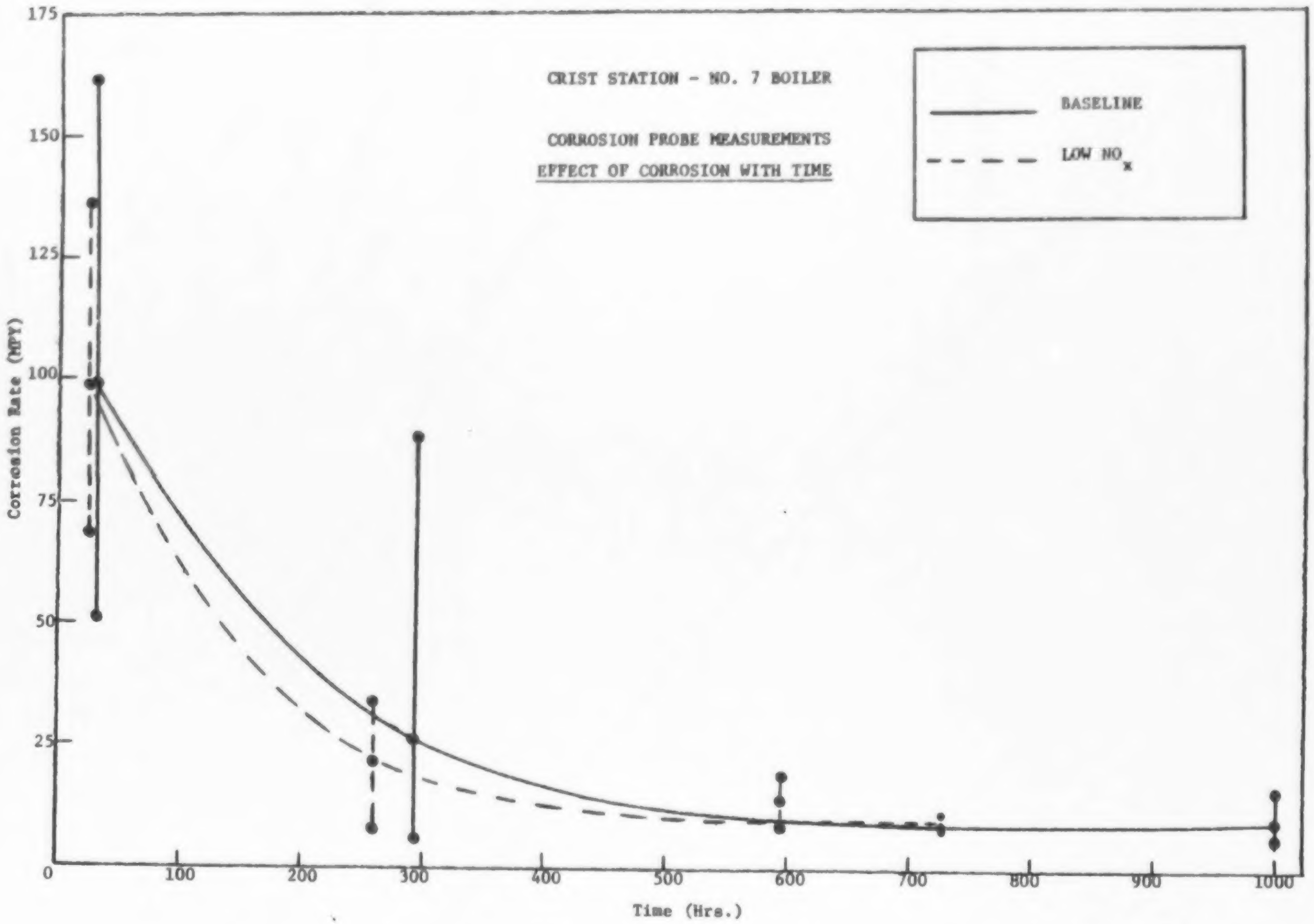

Figure 6. Effect of corrosion with time.

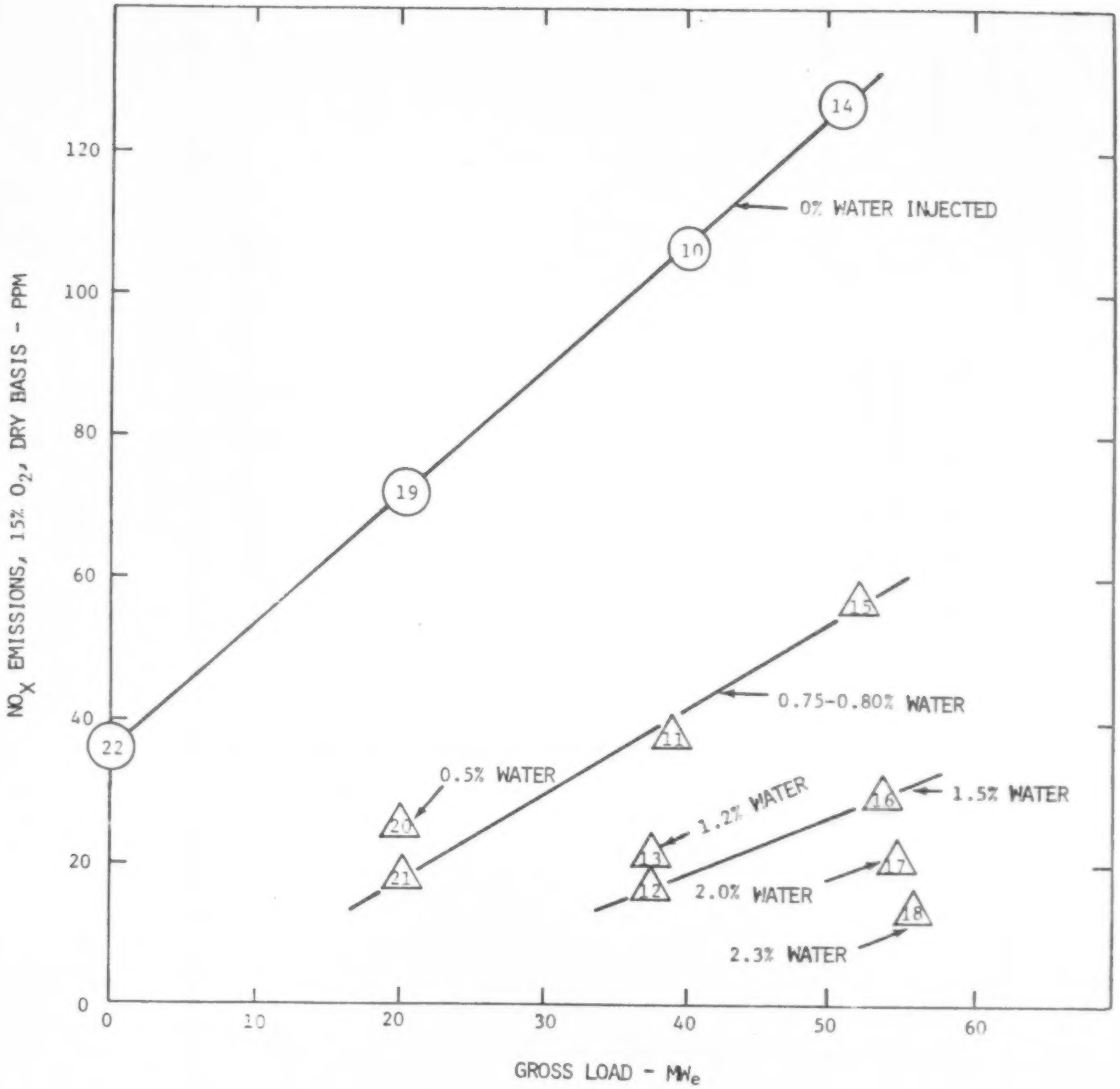

Figure 7. PPM NO$_x$ emissions vs gross load on Wharton No. 42, firing oil.

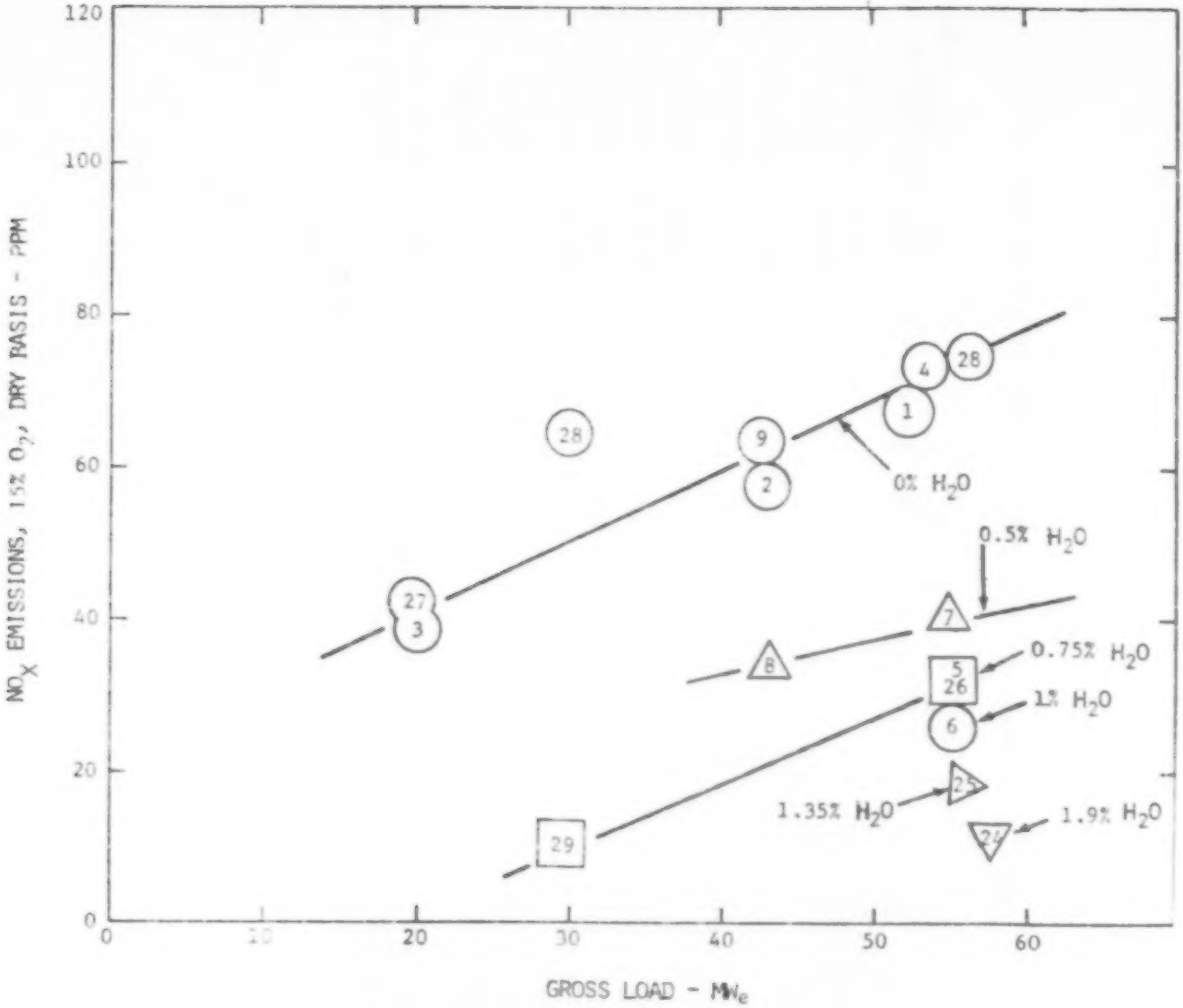

Figure 8. PPM NO$_x$ vs gross load - Wharton No. 43 unit firing gas.

TABLE 1. SUMMARY OF COAL AND MIXED FUEL FIRED BOILERS TESTED

Boiler Operator	Station and Boiler No.	Boiler Mfr. (a)	Type of Firing (b)	Fuel Burned (c)	MCR (MWe)	No. of Burners	Test Variables	No. of Test Runs	NO_x Emissions		
									Baseline ppm ($lb/10^6$ BTU) (j)	Low NO_x ppm ($lb/10^6$ BTU) (j)	% NO_x Reduction (i)
Tennessee Valley Authority	Widows Creek-5	B&W	RW	C	125	16	4	31(d)(e)	597 (0.81)	468 (0.64)	22
Southern Electric Generating Company	E. C. Gaston-1	B&W	HO(f)	C	270	18	5	37(d)(e)	591 (0.8)(k)	278 (0.38)	53
Alabama Power Company	Barry-2	CE	T(g)	CG	130	16	6	38	341 (0.46)	189 (0.26)	45
Potomac Electric Power Company	Morgantown-1	CE	T	CO	575	40	5	27	552 (0.75)	403 (0.55)	27
Salt River Project	Navajo-2	CE	T(g)	C	800	56	4	36(d)(e)	492 (0.67)	282 (0.38)	43
Public Service Company of Colorado	Comanche-1	CE	T(g)	C	350	20	4	30(d)(e)	417 (0.57)	261 (0.35)	37
Public Service Electric	Mercer-1	F-W	FW(h)	C	270	24	4	33(d)(e)	1383 (1.88)	876 (1.19)	37
East Kentucky Power Cooperative, Inc.	Cooper-2	B&W	FW	C	220	18	4	101(d)(e)	557 (.76)	483 (.66)	13
Public Service Company of Colorado	Comanche-2	B&W	HO	C	350	32	4	18(d)	726 (.99)	278 (.38)	62
Average of Coal Fired Boilers									628 (.85)	391 (.53)	38

(a) B&W - Babcock and Wilcox
CE - Combustion Engineering
F-W - Foster Wheeler Energy
RS - Riley Stoker

(b) RW - Rear Wall
FW - Front Wall
HO - Horizontally Opposed
T - Tangential
Turbo - Turbo-Furnace

(c) C - coal, C-G - coal gas mixed, C-O - coal-oil mixed (only coal fired results are reported in this paper)

(d) Particulate tests performed on these boilers

(e) Corrosion probe tests performed on these units

(f) Special low NO_x burners

(g) Overfire air ports

(h) Wet bottom furnace

(i) % NO_x reduction at full or near full load

(j) PPM NO_x - 3% O_2, dry basis

(k) Baseline emissions on Unit No. 2

TABLE II. SUMMARY OF NO_x EMISSIONS FOR PULVERIZED COAL, WALL-FIRED BOILERS

FULL LOAD

Boiler-Type of Firing (a)	Operating Mode (Gross Load - MWe)	% O_2	NO_x Emissions			ppm CO (3% O_2)
			ppm (3% O_2)	$\frac{\text{Lb.}}{10^6 \text{ Btu}}$	ng/J	
1. Widows Creek No. 5-RW	Base - 125	4.0	597(567)(b)	0.81	349	29
	"Low NO_x - I" - 125	3.2	468	0.64	274	88
2. Ernest C. Gaston No. 1-HO (Low NO_x Burners)	Base (No. 2 Unit)- 270	4.3	591(491)(b)	0.80	348	36
	"Low NO_x - I" - 270	2.4	278	0.38	163	65
3. Mercer No. 1-FW	Base - 290	3.9	1383(1354)(b)	1.88	809	22
	"Low NO_x - I" - 284	1.8	876	1.19	512	--
4. Cooper No. 2-FW	Base - 208	3.1	557(575)(b)	0.76	325	30
	"Low NO_x - I" - 205	2.6	483	0.66	282	61
5. Comanche No. 2-HO (Overfire Air Ports)	Base - 358	5.2	726(488)(b)	0.99	425	19
	"Low NO_x - I" - 355	4.5	278	0.38	163	63
	Average	Base	771			
		Low NO_x	477			
		% Reduction	38			

(a) Types of Firing: RW, rear wall; HO, horizontally opposed; FW, front wall.

(b) Baseline NO_x emissions calculated for 20% excess air operation.

TABLE III. SUMMARY OF NO_x EMISSIONS FOR PULVERIZED COAL, TANGENTIALLY FIRED BOILERS

FULL LOAD

Boiler	Operating Mode (Gross Load - MWe)	% O_2	NO_x Emissions ppm ($3\%\ O_2$)	Lb./10^6 BTU	ng/J	ppm CO ($3\%\ O_2$)
1. Navajo No. 2	Base - 800	4.8	492(400)(a)	0.67	288	64
(Overfire Air Ports)	"Low NO_x - I" - 802	3.6	282	0.38	165	330
2. Comanche No. 1	Base - 323	4.0	417(370)(a)	0.57	244	27
(Overfire Air Ports)	"Low NO_x - I" - 333	3.7	261	0.35	153	35
3. Barry No. 2	Base - 130	4.9	341(250)(a)	0.46	199	22
(Overfire Air Ports)	"Low NO_x - I" - 129	3.3	189	0.26	111	49
4. Morgantown No. 1	Base (b) - 570	4.9	552(534)(a)	0.75	323	21
	"Low NO_x - I" - 572	4.7	403(c)	0.55	236	20
	Average	Base	451			
		Low NO_x	284			
		% Reductions	37			

(a) Baseline NO_x emissions calculated for 20% excess air operation.

(b) Fuel burned = 93% coal, 7% oil.

(c) Fuel burned = 74% coal, 26% oil.

TABLE IV. PARTICULATE MASS LOADING RESULTS(a)

Boiler	Firing Condition	Load MWe	Mass Loading			Carbon on Flyash, Wt %	Ash in Coal, Wt %
			Gr/SCF	ng/J	lb/MBtu		
Widows Creek No. 5	Baseline	124	4.45	2290	5.33	9.1	18.3
	Low NO_x	125	3.55	1830	4.26	8.1	12.3
E. C. Gaston No. 2	Baseline	272	4.74	2550	5.94	1.9	15.0
E. C. Gaston No. 1	Low NO_x	268	5.05	2670	6.20	4.4	10.6
Navajo No. 2	Baseline	792	2.86	1580	3.7	1.6	7.8
	Low NO_x	805	4.22	2290	5.3	1.2	8.1
Comanche No. 1	Baseline	324	2.58	1350	3.1	0.6	5.4
	Low NO_x	321	2.13	1120	2.6	0.3	5.4
Mercer No. 1	Baseline	267	1.95	1100	2.6	1.9	9.9
	Low NO_x	267	2.32	1230	2.9	3.5	9.9

(a) Flue gas stream measured at air heater outlet upstream of particulate collector.

TABLE V. TYPICAL PARTICLE SIZE DISTRIBUTION, WT. %

BRINK CASCADE IMPACTOR

Size Range	Navajo No. 2		Comanche No. 1		Mercer No. 1	
	Base	Low NO_x	Base	Low NO_x	Base	Low NO_x
>2.5μ	92.7	93.9	81.8	80.7	85.0	86.4
2.5μ	3.0	1.9	8.9	8.9	3.5	5.3
1.5μ	0.7	0.6	2.0	2.3	2.3	1.8
1.0μ	1.0	0.9	2.6	2.9	2.2	2.0
0.5μ	1.2	1.1	2.9	3.3	1.2	1.2
<0.5μ	1.4	1.6	1.6	1.9	5.8	3.3

TABLE VI. SUMMARY OF BOILER PERFORMANCE CALCULATIONS

Boiler	Firing Mode	Load, MWe	% O_2	NO_x Emissions Corrected to 3% O_2 PPM	Coal Ash, % (Wet Basis)	% Carbon on Particulate	Boiler Efficiency, %
Widows Creek No. 5	Baseline	124	2.5	441	18.27	9.1	86.2
	Low NO_x	125	2.5	412	12.30	8.1	87.3
E. C. Gaston No. 1	Baseline	270	4.2	606	13.28	2.1	89.2
	Low NO_x	270	3.9	349	12.12	5.7	89.2
Navajo No. 2	Baseline	792	3.9	332	5.94	1.8	89.6
	Low NO_x	798	3.7	280	6.04	1.5	89.7
Comanche No. 1	Baseline	325	3.7	380	5.36	0.66	80.8
	Low NO_x	330	3.4	205	5.62	0.59	80.3
Mercer No. 1	Baseline	267	3.4	1113	9.93	1.9	90.2
	Low NO_x	267	1.9	897	9.90	3.5	90.1

TABLE VII. TYPICAL WET CHEMICAL SO_2/SO_3 FLUE GAS ANALYSES

Generating Station/Boiler	Firing Mode	O_2 %	Calculated SO_x(a) ppm	Measured SO_x SO_2 ppm	Measured SO_x SO_3 ppm	SO_3/SO_2 Mole Ratio
Comanche No. 1	Baseline	3.0	376	224	9	0.034
	Low NO_x	3.0	(b)	238	10	0.035
Salt River No. 2	Baseline	3.0	393	330	6	0.018
	Low NO_x	3.0	(b)	207	10	0.047
Mercer No. 1	Baseline	4.4	1039	980	10	0.010
	Low NO_x	2.4	990	722	10	0.014

(a) Based on 100% conversion of fuel sulfur to SO_x.

(b) Fuel analysis not available.

TABLE VIII. FIRESIDE CORROSION RATE MEASUREMENTS
(300 Hour Corrosion Coupon Exposure)

Boiler	Firing Condition	Coupon Corrosion Rate Mils/Yr.
Harllee Branch No. 4	Baseline	73(a)
	Baseline	37(a)
	Low NO_x	75(a)
	Low NO_x	115(a)
Widows Creek No. 6	Baseline	12
	Baseline	11
No. 5	Low NO_x	15
	Low NO_x	13
E. C. Gaston No. 2	Baseline	9
	Baseline	7
E. C. Gaston No. 1	Low NO_x	14
	Low NO_x	9

(a) Accelerated corrosion tests.

TABLE IX. SUMMARY OF NO_x, CO AND HC EMISSIONS FOR GAS AND OIL-FIRED GAS TURBINES

			Emissions					
			O_2	NO_x			CO	HC
Gas Turbine	Fuel Burned	Operating Mode -Gross Load, MWe	%	ppm (15% O_2)	Lbs./10^6 BTU	ng/J	ppm (15% O_2)	ppm (15% O_2)
1. Morgantown Station Gas Turbine No. 3	No. 2 Fuel Oil	Base - 54	14.7	133	0.58	224	81	5
		Base - 48	15.2	125	0.55	214	30	6
		Base - 25	17.3	101	0.47	182	4	10
		Base - 10	17.9	82	0.36	138	4	24
2. Wharton Station Gas Turbine No. 42	No. 2 Fuel Oil	Base - 51	15.3	127	0.50	214	4	3
		2.3 H_2O - 55.5	14.6	13	0.05	22	53	2
		Base - 40.0	16.5	106	0.41	178	3	3
		1.5% H_2O - 37.5	16.4	17	0.07	29	142	20
		Base - 20.0	17.3	72	0.03	121	19	3
		0.8% H_2O - 20.0	17.4	19	0.07	31	114	19
3. Wharton Station Gas Turbine No. 43	Natural Gas	Base - 54	15.5	73	0.26	112	4	2
		1.9% H_2O - 56	15.1	11	0.04	17	60	51
		Base - 43	16.0	62	0.22	95	4	4
		0.5% H_2O - 43	16.0	34	0.12	52	7	4
		Base - 30	17.5	64	0.23	97	18	5
		0.75% H_2O - 30	17.6	10	0.04	15	336	131
		Base - 20	18.1	42	0.15	64	42	10

CORROSION TESTING OF UTILITY BOILER COMBUSTION MODIFICATIONS

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ABSTRACT

Previous Exxon Research and Engineering Company field studies have shown that NO_x emissions from coal fired utility boilers can be reduced by about 30 to 50 percent by combustion modifications. Simultaneous studies of side effects of combustion modifications showed no significant problems in short term tests. However, only limited and inconclusive data are available on the effect of combustion modification on fireside corrosion rates of boiler tube walls. Exxon is presently under contract to the United States Environmental Protection Agency to determine the long term effect of combustion modifications on the corrosion rate of furnace tube walls of four new coal fired utility boilers designed to meet the New Source Performance Standard of 0.7 $lb/10^6$ Btu (301 mg/J) for NO_x emissions. The respective manufacturers of these boilers will be involved as subcontractors in this long term corrosion test program. Comprehensive emission measurement programs will be conducted in parallel with the corrosion tests on the four boilers selected for this study. Corrosion rates will be determined in two-year test programs on each boiler by three methods--installation of corrosion panels in the furnace tube walls, ultrasonic mapping of furnace tube wall thicknesses, and exposure of corrosion probe coupons. This paper reports the work planned and the present status of this contract.

ACKNOWLEDGEMENTS

Exxon Research and Engineering Company wishes to thank Mr. David Lachapelle, the EPA Project Officer on this contract for his guidance. We also acknowledge the cooperation of boiler manufacturers and electric utilities without which this program would not be possible.

INTRODUCTION

Exxon Research and Engineering (ER&E) Company under contracts funded by the United States Environmental Protection Agency (EPA) has shown in short term tests typical NO_x reductions of 30 to 50% from coal fired utility boilers by modification of the combustion process (1). Subsequent short term studies of the side effects of combustion modification did not reveal any significant problems (2) with the possible exception of aggravated furnace tube wall corrosion and slagging that may result from the fuel rich conditions associated with staged combustion of coal, particularly with high sulfur content. Short term corrosion rate measurements have since demonstrated that low NO_x firing of coal does not result in catastrophic corrosion tendencies, however, actual wastage rates could not be determined from these measurements. Currently, U.S. boiler manufacturers rely on combustion modifications such as staged combustion and/or low NO_x burner design to meet the New Source Performance Standard (NSPS) of 0.7 $NO_x/10^6$ Btu for new coal fired boilers. Additional boiler flexibility for combustion modification on NSPS boilers is provided by additional combustion control features such as tiltable burners, variable flue gas recirculation and overfire air. A key question is whether combustion modifications, particularly for high sulfur coals will result in accelerated tube wall corrosion rates, and if they do, what engineering solutions need to be employed.

The long term (2-year) corrosion studies to be done under this program (3) will be performed on four new coal fired utility boilers which have been designed by their manufacturers to meet the new source performance standards (NSPS) for NO_x emissions (0.7/m Btu). U.S. boiler manufacturers (Babcock and Wilcox, Combustion Engineering and Foster Wheeler) will function as Exxon's subcontractors in performing the long term corrosion tests on boilers of their design.

Because of the potential corrosion problems associated with low NO_x operation, a special long term corrosion study was made under a previous contract (4) at the #7 unit of Gulf Power Company's CRIST Generating Station in Pensicolà, Florida. CRIST #7 is a 500 MW, horizontally opposed, coal fired boiler containing 24 burners and manufactured by Foster Wheeler. It is a pre-NSPS unit.

Sections of boiler wall tubes were replaced with specially measured and characterized sections (corrosion panels). Approximately one year later, these special sections were removed and corrosion rates were determined. Gulf Power Company agreed to operate under low NO_x conditions to the extent practical during the one year test, in accord with guidelines based upon extensive tests at that boiler and others. Tube wall thicknesses were ultrasonically measured at hundreds of points within the boiler to provide a thorough map of tube wall thickness both before and after the one year corrosion panel exposure period. Corrosion rates were measured by probes, replaceable wall tube panels, and ultrasonic thickness mapping. Furnace gas composition was mapped by gas taps, and boiler operating data were recorded from the control room instruments. Data were gathered to check the correlation between these different variables to determine if simpler techniques could provide the corrosion information desired.

The new program involving NSPS boilers will include all of the corrosion tests performed at CRIST #7, in addition to other comprehensive testing described in the next section of this paper.

PROGRAM

OBJECTIVES

During the test program, extensive corrosion data will be gathered by probes, panels (removable tube wall sections), and periodic ultrasonic thickness (UT) mapping. An attempt will be made to show correlation among these three sets of data and with data from older programs. Boiler performance and flexibility will be evaluated. Corrosion rates will be correlated with operating conditions (base, low NO_x, etc.). Other side effects of NSPS low NO_x operation will also be evaluated, including complete pollutant assessment by a Level 1 test, and a 30-day continuous flue gas monitoring period with extensive reference method and calibration checks at each boiler.

BOILER SELECTION

Each of the four boilers in this test program represents designs of the four major manufacturers and as such, the manufacturers have worked closely with us recommending candidate host sites. Each boiler burns high sulfur (>2.25 wt %) bituminous coal and produces more than 125 MW of electricity. These boilers were designed to meet the New Source Performance Standards (NSPS) for NO_x emissions of 0.7 $lb/10^6$ Btu.

TEST PROGRAM DESIGN

A specific test program is designed for each boiler selected so that the effects of each operating variable on a particular boiler can be statistically evaluated. Independent variables include fuel feed rate, burner tilt, overfire air flow rate and total air/fuel ratio. Dependent variables include boiler efficiency, slagging rate, gaseous and particulate emissions, and corrosion rates. Time and cost considerations will not allow a separate test of each combination of operating variables, thus emphasizing the importance of statistically designed test programs.

BOILER CHARACTERIZATION

Before corrosion testing can begin, the safe limits of boiler flexibility are determined. This involves a statistically designed program lasting several weeks during which (determine) the effect of the various combustion controls on emissions and boiler efficiency will be determined. During this period detailed records of operating conditions and flue gas composition are kept. Two conditions of special interest are established and quantified:

Baseline: Uncontrolled, operation at full load.

Low NO_x: Full load with combustion controls safely set to yield lowest practical NO_x emissions.

Having established the optimum operating conditions for low NO_x emissions, the boiler is operated at these conditions for 2 to 3 days. During this period problems not found during the shorter tests, such as slagging and fouling, can be detected and corrected by adjustment of operating conditions, thus redefining the optimum low NO_x conditions. Corrosion rates are then measured at both baseline and low NO_x conditions.

CORROSION RATE MEASUREMENTS

Tube wall corrosion rates are measured by three methods: probes, ultrasonics mapping, and panels. Furthermore, furnace gas composition is monitored in areas of high anticipated corrosion, as well as in certain control areas where corrosion is not expected to occur.

Furnace Gas Composition

At the start of the test program, furnace gas taps are installed through the furnace walls in 30 statistically selected locations. Gas samples are withdrawn and analyzed from each of the taps at various typical operating conditions so that highly corrosive local furnace environments can be identified.

Corrosion Probes

After analysis of the gas tap data and identification of corrosive regions of the furnace, 5 corrosion probes are installed through selected points of the furnace walls where more detailed corrosion data are desired. Each corrosion probe consists of several specimens (called coupons) of boiler tube material and other alloys affixed to an air cooled support such that the coupons are maintained at normal tube wall temperature (∿650-700°F). The probes are inserted through the tube walls into the furnace where they remain for 30, 300, or 1,000 hours. Corrosion rate is determined by weight loss analysis. Because of the simplicity and relatively short duration of corrosion probe tests it is possible to use this method to determine relative corrosion tendencies under a variety of conditions (including base and low NO_x) within a few weeks. This method can also be used to "spot check" corrosion rates.

Data from the corrosion probe test will:

1. Aid in locating corrosion panels.
2. Establish possible corrosion problems early in the program so that less corrosive operating conditions can be selected if necessary.
3. Correlate furnace gas composition with probe corrosion rates.
4. Allow correlation of corrosion data between this boiler and other boilers tested during previous programs.
5. Allow comparison between corrosion rates at low NO_x and baseline conditions.
6. Determine applicability of short term corrosion tests to the prediction of long term corrosion rates.

Ultrasonic Thickness (UT) Measurements and Corrosion Panels:

Long term (1 to 2 year) low NO_x operation will begin only after the shorter tests, just described, establish problem free operation under low NO_x conditions. Prior to the start of the two year low NO_x operating period, the boiler is entered during a scheduled outage and selected sections of wall tubes are removed from the boiler circuit and replaced with approximately 6 carefully characterized sections called corrosion panels, each about 5 to 10 tubes wide and 10 feet long. The location of the panels will have been determined from gas tap and corrosion probe information. In this way, more data can be collected in certain locations of interest. Each panel contains three thermocouples so that a temperature history of the boiler walls can be recorded. While the panels are being installed, ultrasonic thickness measurements are performed at hundreds of points encompassing 6 elevations of each wall of the interior of the boiler furnace. This information provides a thickness map of the boiler walls prior to low NO_x operation.

The ultrasonic thickness measurements have been carefully planned so that subsequent cleaning and measurement of the same vicinities at a later time will yield statistically meaningful results. The cleaning procedure used to prepare the surface is designed not to interfere with the measurement. Periodic visits will be made to the boiler during the 2 year period of low NO_x operation to measure emissions, corrosion rates by probes, and verify the effectiveness of low NO_x operation. Ultrasonic thickness measurements will be performed twice more during the 2-year test, and a section of each corrosion panel will be removed for analysis during each UT measurement period. This analysis includes physical measurements as well as chemical analysis of slag, deposits, and the metallurgical characterization of tube wall material.

Since periodic corrosion probe tests will have been made during the 2 year corrosion panel exposure period, it should be possible to correlate data from probes, panels, ultrasonic thickness measurements, and furnace gas taps.

EMISSION TEST PROGRAM

During the period of boiler characterization, flue gas monitors are used to record NO_x and other emissions while combustion control parameters are varied to explore optimum low NO_x conditions. Flue gas composition will also be monitored periodically during the 2 year period of low NO_x operation, especially while corrosion probe tests are in progress. More extensive emission measurements done during low NO_x operation include a Level 1 test of effluent streams, and a period of 30 days during which emissions are monitored continuously.

Flue Gas Analysis

Flue gas is monitored at 12 points between the economizer and air heater according to procedures that have been shown to yield meaningful results (5). The monitors are contained in a mobile emissions sampling van and include O_2, CO, CO_2, light hydrocarbons, NO, NO_x, and SO_2 analyzers. SO_2 and SO_3 are also measured by wet chemical methods.

Level 1 Test

A Level 1 test is performed once on each boiler during its low NO_x operating period. This is an extensive pollutant assessment test involving all pertinent streams solid, liquid, and gas entering or leaving the boiler. Gas and particulate samples are taken upstream and downstream of the electrostatic precipitator (ESP) so that the effect of low NO_x operation on particulate loading and composition and ESP efficiency can be determined by comparison with similar tests done at base conditions earlier in the program. Level 1 tasks also include fuel analysis, and biological toxicity tests of flue gas particles, bottom ash, and precipitator ash.

The source assessment sampling system (SASS), a modified Method 5 train, is used for flue gas and particulate sampling. It gives information on size distribution, and trace species concentrations as well as data on polychlorinated biphenyls (PCB) and polycyclic organic matter (POM).

Continuous Monitors

The low NO_x operating period will include 30 days of continuous monitoring for NO/NO_2 and SO_2 according to EPA guidelines and with frequent reference method checks. An attempt will be made to run this test concurrently with the Level 1 test, corrosion probe tests, and flue gas analyses.

PRESENT STATUS AND PLANS

As of this writing, agreement has been reached with two utilities for testing of their units with the restective boiler manufacturers.

- Columbus & Southern Ohio Electric Company
  Conesville Unit 5 (410 MWe)
  Manufacturer: Combustion Engineering, Inc.
  Start of Testing: Fall, 1978

- Louisville Gas & Electric Company
  Mill Creek Unit 3 (450 MWe)
  Manufacturer: Babcock & Wilcox
  Start of Testing: Spring, 1979

Foster Wheeler is presently screening a number of candidate units suitable for long term testing. This boiler should be selected by early 1979.

A fourth unit has yet to be selected. Manufacturers are screening their customers for a candidate boiler. It is expected that this unit will be selected early in 1979.

IN SUMMARY

The data gathered during this program will determine the effects of various combustion controls on flue gas emissions and boiler efficiency. These, together with careful observations of side effects such as slagging and fouling will help determine optimum operating conditions for low NO_x emission for large, high-sulfur coal fired, NSPS utility boilers. Corrosion rates will be determined at this low NO_x condition and a basis will be established for comparison with corrosion rates at base conditions. The effects of low NO_x operation will be extensively quantified and compared with baseline emissions. Toxicity of specific effluents will also be determined under low NO_x conditions by biological testing.

The data are expected to yield valuable information to utility boiler operations and manufacturers on corrosion rates under low NO_x operating conditions of coal fired NSPS boilers. This information will be used to determine whether corrective measures are required to reduce corrosion rates resulting from low NO_x firing of coal.

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FIELD EVALUATION OF LOW NO_x COAL BURNERS ON INDUSTRIAL AND UTILITY BOILERS

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INTRODUCTION

The trend in the U. S. is to the increased use of coal for industrial and utility heat and steam generation with the potential for an attendant increase in pollutant emissions. For example, a recent report (1) has estimated that NO_x emissions might increase by up to 80 percent by the year 2000 for a scenario of high coal usage with current control technology. Therefore, the EPA program for development of advanced combustion concepts is directed toward optimum control of NO_x and other pollutants from a range of conventional coal utilization technologies. The program, which addresses not only direct combustion of coal, but also solid, liquid, and gaseous fuels that may be derived from coal and/or shale, has been described in a recent paper (2). A major element of that program is the development and field evaluation of pulverized coal combustion techniques directly applicable to conventional steam generators.

The purpose of this paper is to briefly describe the recently initiated projects for field evaluation of a low NO_x burner concept on industrial and utility steam generators.

BACKGROUND

The development of the low emission coal burner was initiated in 1970 under a contract with the International Flame Research Foundation for a study of the effects of burner design on emissions from pulverized coal combustion. The results led to the conclusion that NO_x formation resulted predominantly from the conversion of nitrogen compounds released with the volatile matter and that a burner design which reacted the volatiles in a fuel-rich atmosphere could result in very low conversions to NO_x (3).

A triple concentric burner design was developed which created the optimum conditions for low NO_x emissions while maintaining the flame shape required for boiler application. This development work was done at 2 to 3 thermal MW (6-9 X 10^6 Btu/hr) in a refractory tunnel. Both burner scale-up to nearer practical size and performance evaluation in a system having more realistic geometry and heat transfer characteristics were required.

The development of scale-up criteria was initiated under a contract with Energy and Environmental Research Corporation. As a part of that contract a versatile experimental facility capable of simulating the geometry and heat transfer characteristics of a field-erected watertube boiler was constructed. The configuration of the firebox is shown in Figure 1. The most significant features are: 1) up to 40 thermal MW rated capacity for either single or multiple burner arrays; 2) variable geometry for constant volumetric heat release over the range of firing rates; 3) water-spray cooled sheet steel walls for control of temperature; and 4) flexibility of operation over a wide range of well controlled conditions. A smaller system simulating a D-type package watertube and capable of firing up to 4 thermal MW was constructed for burner design screening. Using these two facilities, a distributed mixing burner was developed. One experimental burner configuration, shown schematically in Figure 2, has three points for addition of combustion air: 1) primary air used to transport the pulverized coal; 2) secondary air admitted through two annular channels around the fuel pipe; and 3) tertiary air admitted through four ports located around the burner perimeter. The amount of air admitted through each can be controlled independently to determine optimum conditions. The secondary air is divided into two streams with independent swirl to allow not only flame shape tailoring but also increased turndown flexibility. The burner variables that influence NO_x emissions include: 1) primary air percentage and velocity; 2) fuel injector design; 3) secondary air percentage, velocity, and swirl distribution; 3) quarl design; and 4) tertiary air percentage, velocity, direction, and displacement from burner centerline. A representative graph of results obtained at a nominal 15 thermal MW is shown in Figure 3, where NO_x emissions are plotted versus excess oxygen in the flue gases. The major variable is the amount of secondary air. With the primary air maintained at 25 percent of theoretical, secondary air was controlled to give total air through the burner throat over the range of 50 to 110 percent of theoretical air. The balance of the air was admitted through the tertiary ports to bring the total air to the stated excess oxygen conditions. For this particular case NO_x emissions range from approximately 500 ppm down to less than 100 ppm. To examine the effects of scale, three geometrically scaled burners were constructed and tested. The 4 thermal MW burner was tested in the small system watertube simulator while the 16 and 35 MW burners were tested in the large watertube simulator at comparable volumetric heat release rates. Data for all three burners, run at an "optimum" condition for the 16 MW burner, are shown in Figure 4. The NO_x level for the 16 MW burner is significantly lower than for the 4 MW burner while the 35 MW results fall in between. Further work on the effects of scale is in progress to explain these observations.

Having established the potential of the low NO_x burner concept for a limited number of coal types, the development program was expanded to extend its applicability to the full range of U. S. coals, to further optimize single burner concepts, and to explore additional multiple burner configurations. The approach is to use a small scale furnace for screening of fuels and concepts followed by large burner experiments on fuels and concepts of specific interest. The fuels selected for the screening cover the full range of U. S. coals from anthracite to bituminous plus selected foreign coals. In addition, chemically and/or physically cleaned coals will be included as they become available. Based on the results of the small scale screening of about 36 coals, 12 will be selected for burner testing at a nominal 4 thermal MW and 6 for testing at the larger scale (15 to 40 MW). The results of these tests will establish criteria for optimizing burner performance as a function of fuel characteristics. The small scale furnace will also be used to screen other combustor concepts capable of achieving lower emission. A more extensive discussion is presented elsewhere in this Symposium for both the small scale fuel experiments (4) and the pilot scale development work (5).

To provide a basis for widespread application of the technology to pulverized coal fired boilers it is necessary to evaluate the long term performance of prototype burners in field boilers. The purpose of this paper is to describe the general structure of two programs to perform this field evaluation.

DISCUSSION

A significant fraction of industrial and utility steam generators are coal fired and projects indicate that the fraction will increase. While stoker firing shares the market in the smaller sizes, pulverized firing dominates the large industrial and new utility boiler market. For both sectors, multiple burner watertube boilers of a variety of designs are used. The principal distinctions between the sectors are boiler capacity, duty cycle, and steam quality. Industrial boilers are generally below 293 thermal MW (a nominal 10^6 lb of steam/hr) and supply process steam; whereas, new utility boilers are substantially larger (e.g., 600 electrical MW) and supply high pressure superheated steam for electric generation. While the similarities are sufficient to make the low NO_x burner technology equally applicable to each, the differences require a separate evaluation of the technology for each class of boilers. For purposes of the program, the target size range for the field evaluation boilers was 29 to 145 thermal MW (100 to 500 thousand lb of steam/hr) for the industrial boilers and 100 to 300 electrical MW for the utility boilers. Two boilers of each type will be evaluated.

The field evaluation of the low NO_x coal burner must address a variety of technical issues on the translation of an experimental technology into a system that can be used in practical steam generators. Since the experimental burners have been tested at heat inputs comparable to burners currently used in many industrial and utility boilers, it appears that the classical problems of scale up should be minimized. The remaining problems are related to mechanical reliability and operational flexibility of the prototype burners. The specific requirement imposed on the burner design will depend on the characteristics of the host boiler. Other aspects of the program, such as schedule, will also be impacted by the boiler selection. Therefore, the field evaluation program requires the definition of host boiler requirements and the selection of specific sites as the first step. This is followed by the design of a prototype burner to meet the specific requirements for each host boiler. Based on the design phase for each boiler, a prototype burner can be fabricated and mechanical operability and performance optimization can be carried out in the experimental system. This prototype testing will allow the specification of the final burner configuration for each boiler. The field evaluation will entail the fabrication and installation of the required number of burners, the reoptimization of performance in the boiler, and the long term operation under practical conditions. Finally, the results must be used to generalize the technology for application to the full range of U. S. boiler designs and coal types.

PROGRAM STRUCTURE

The program of the field evaluation is virtually the same for industrial and utility boiler contracts, with some differences in the detailed requirements. The scope of work consists of nine tasks which are discussed below.

Program Definition

The program definition task provides for the initial planning and continuing review and management of the contract effort. Specific elements include: host boiler selection, engineering design of the prototype burner, definition of the measurement plan, and preparation of an overall program plan.

Boiler Selection--

The results of this subtask will establish the requirements to be satisfied in all other tasks of the contract. Existing information will be screened to establish design and operating characteristics of the specific boiler population of interest. This study will deal with historical data on existing boilers and with projections of trends for future sales. Based on this, a set of criteria will be derived for selection of two boilers of distinctly different characteristics required to show the generalization of the technology. Following these criteria, a list of existing boilers will be assembled and used to select potential host sites. This list will be screened for additional desirable characteristics, such as: 1) redundant capacity at the host site to allow the greatest flexibility in the test program, 2) continuous steam requirement to maximize data collection over the evaluation period, 3) past characterization of emissions, and 4) good history of reliable operation with minimum problems. The potential hosts will be contacted to determine their interest in participating in this program and detailed discussions will be held with all potential hosts. The contractor and the EPA project officer will make a final selection of host sites based on the results of this process. Following final negotiations with the hosts, the contractor will prepare a site specific plan for each boiler, including: 1) schedule of work, 2) provision of required clearances, 3) definition of equipment lead time, 4) schedule of boiler outage, and 5) coordination of all involved parties.

Burner Engineering Design--

The experimental data on the low NO_x coal burner will be translated into a prototype burner design engineered to meet the specific requirements of each host boiler. This design package will include specifications not only of the burner but also of all support and auxiliary systems required to interface the burner to the boiler. It will also identify compliance with all codes governing fabrication, installation, and operation of the burners. The burner design package will be subjected to detailed review by the EPA, the representatives of the host site, and an independent committee of experts, prior to final approval.

Analytical Measurements--

The approach to the measurement of pollutant emissions and boiler thermal performance must be defined in a measurement protocol to ensure that the data from the study are complete and accurate. The frequency with which any given measurement is made will depend on both the complexity and the costs involved. The protocol will specify the measurement frequency for input and output parameters. For monitoring performance of the burners, certain gas phase species (CO, O_2, and NO_x) will be monitored continuously over the duration of the long term tests. Other gas phase species (NO, SO_2, and HC) will be measured periodically. Under conditions that warrant further investigation, more extensive measurement will be made including: 1) particulate mass, 2) ash carbon content, 3) SO_3, and 4) sulfur retention in the ash. Finally, for a very limited number of conditions, a comprehensive analysis of the combustion side effluent streams will be made. The procedures to be used for this comprehensive analysis will satisfy the requirements of the EPA's Environmental Assessment procedures (6).

The periodic gas phase measurements and the more comprehensive analysis of the effluent streams will be made during three to five 30-day detailed measurement periods during boiler baseline characterization and long term performance evaluation. For the 18 month evaluation, two of the 30-day periods will occur in the first and last months, with the balance equally spaced in between. Detailed evaluation of the thermal performance will also be conducted during these periods.

Overall Program Plan--

The results of the three subtasks discussed above will be combined into a program plan covering all aspects of the performance evaluation. This plan will be reviewed periodically as part of overall contract management.

Prototype Construction and Testing

The first step in the evaluation of the prototype burner design discussed above is the comparison of its performance to that of the experimental burner on which it was based. For each host site one prototype burner will be constructed and tested in the large watertube simulator (LWS) (see Figure 1). This testing will be carried out with both the baseline coal from the burner development study and the coal being used at the host site. The prototype burner will be operated over a range of conditions simulating the requirements of the host site duty cycle. The performance of the burner will be optimized and any mechanical problems will be rectified. Once the burner design has been verified, comprehensive measurements will be made for selected operating conditions. Any modifications of the burner will be incorporated in the design package. A direct comparison of the prototype burner to the original equipment manufacturer's (OEM) burner as installed at the host site will be made. The OEM burner will be installed in the LWS and operated over a range comparable to the prototype burner. The results of this comparison will be used to estimate the performance of the prototype burner in the host boiler and will provide additional data for generalization of the technology.

Boiler Baseline Evaluation

The detailed measurement of the host site boiler operating at the normal duty cycle will provide a benchmark for evaluation of the performance of the low NO_x burner. The baseline evaluation will be directly comparable to a 30-day detailed evaluation period to be run with the low NO_x burner and will include both continuous gas phase measurements and comprehensive analysis of samples at selected conditions. The boiler will also be operated under modified conditions (e.g., low excess air, staged combustion) to determine the degree of NO_x reduction achievable by tuning the existing firing system. These tests will be of short duration and detailed measurements will be limited.

Burner Installation

Following the baseline characterization, a scheduled outage will allow installation of the required number of prototype low NO_x coal burners and all support systems in each host boiler. Other equipment for complete evaluation of the technology will be installed, including: 1) air and fuel flow measurement and/or control, 2) boiler thermal performance instrumentation, 3) wallports for sampling and/or observation, 4) a color TV camera and videotape for remote flame observation, and 5) removable tube panels for corrosion evaluation. In addition, there is an option for a 30 day evaluation of dry SO_x control on one industrial boiler if pilot scale results and short term tests on the boiler warrant. Ultrasonic measurements will also be made to determine boiler wall thickness at a number of locations not covered by the corrosion panels. Finally, the boiler will be checked out and started up using normal procedures and the operability of all systems will be verified. The boiler will be operated over the normal load range to establish that the low NO_x burner performs in a manner fully comparable to the unmodified boiler.

Performance Evaluation

The performance evaluation task is the heart of the low NO_x burner program. The first step is the optimization of the burner performance for the specific host boiler. The initial burner settings for low NO_x operation will correspond to those identified during testing in the LWS. The burner conditions will also be varied to determine if the optimum condition in the multiple burner boiler is significantly different than those chosen based on the experimental single burner system. In addition, the use of overfire air and/or biased firing may be explored to determine if further NO_x reduction is achievable.

The final burner settings for long term operation will be selected based on minimum NO_x achievable with low carbonaceous emissions, good flame stability, and acceptable load-following characteristics. Then the 18 month performance evaluation will commence. Detailed measurement of thermal and emission performance will be conducted during the initial 30 day period of operation under normal duty cycle. Detailed 30 day duration measurements will be made periodically during the next 16 months (one to three periods depending on need) and again during the 18th month. The contractor will provide for continuous monitoring of NO_x, CO, and O_2 during the 18 months. An onsite representative will monitor the overall burner performance, provide for any service required on the burners, investigate the causes of any shift in emission performance, and reduce data on a continuing basis.

Industry Coordination

The purpose of this task is to secure the advice of manufacturers and users of pulverized coal burners on practical aspects of the technology and to ensure the timely dissemination of the program results to potential users. In addition, both the industrial and the utility boiler evaluation contracts must be coordinated with the continuing development activity to generalize the applicability of the technology to the full range of U. S. coals and to other system configurations. This will be accomplished through the existing Technical Review and Technology Transfer Panels under the development contract (68-02-2667). The Technical Review Panel, which already includes representatives of the field evaluation contractors, will be expanded to include representatives of each host site, and review of all three contracts will be accomplished during the semiannual meetings. The plans for and results of the field evaluation will be communicated to the Technology Transfer Panel, which consists of representatives of Government agencies and industry associations, at the annual meetings.

Restoration

At the completion of the 18 month period, a scheduled outage will be arranged and the boiler will be restored to the configuration when the program began. The corrosion panels will be removed and used to assess the extent of tube wastage. Ultrasonic measurements will be made at the locations measured at the time of low NO_x burner installation. The restored boiler will be started up and checked out to verify that its function is comparable to that at the start of the program.

Data Analysis

Data will be analyzed continuously over the period of the contract. Specific analyses include:

1) Compare experimental burners and prototype burner to identify design changes and establish optimum conditions.

2) Compare prototype burner and OEM burner performance in the LWS to estimate the performance of the low NO_x burner in a multiple burner watertube boiler.

3) Analyze the baseline data to serve as a benchmark for comparison of low NO_x burner performance.

4) Optimize the performance of the low NO_x burner in each host boiler and select the condition having the lowest emission potential.

5) Analyze long term data continuously to detect performance changes and/or define alterations required in burner operation or testing procedures.

6) Verify the procedures for extrapolating the experimental system results into practical burner systems.

Guideline Manual

The ultimate goal of the field evaluation contracts is to provide the basis for widespread application of low NO_x burner technology to industrial and utility pulverized-coal-fired boilers. To assist in accomplishing this goal, a guideline manual will be prepared for each class of boilers. These manuals will summarize the results of the contract and provide information on the methodology of translating the experimental burner data into practical burner design. Specific areas to be covered include the following:

1) A summary of experimental data for single and multiple burners that served as the basis for the prototype burner design.

2) Experimental data on effects of fuel type on burner performance.

3) The design approach for the prototype burner and the method of applying the technology to specific boiler situations. Approach to multiburner effects shall be emphasized.

4) Comparison of prototype and original equipment burners in the LWS to the experimental burner on the same facility.

5) Comparison of performance of the low emission burner in the field operating boilers to projected performance from the LWS experiments.

6) Identification of problem areas and solutions employed during this study.

7) Effects of burner technology on non-criteria pollutants and methods of estimating prior to field test application of a technology.

8) Specific guidelines for application of the burner technology to field operating boilers.

SUMMARY

Low NO_x burner technology has been developed which is capable of achieving NO_x emissions below 86 ng/J (0.2 lb/10^6 Btu) in an experimental single burner system operating at 35 thermal MW (105 X 10^6 Btu/hr). Although this approaches the size of practical burners for large industrial and utility boilers, reliable operation in multiple burner watertube boilers under a normal duty cycle must be achieved before the full potential of the technology can be assessed. Therefore, two programs have been initiated for long term field evaluation of the low NO_x burner technology for industrial and utility boilers. Significant features of each program are as follows:

1) Design and performance verification of prototype burners based on experimental burner results.

2) Installation of the required burners and support equipment on host boilers.

3) Operation of the low NO_x burner under normal duty cycle on each boiler for 18 months.

4) Continuous monitoring of NO_x, CO, and O_2.

5) Three to five detailed 30 day evaluations of emission and thermal performance, with continuous gas phase analysis and more comprehensive analysis on selected conditions.

6) Provision for assessment of total environmental impacts of the technology.

7) Potential for evaluation of dry SO_2 control technology on one industrial boiler.

8) Corrosion evaluation including both removable tube panels and ultrasonic measurements.

9) Preparation of a guideline manual to assist in generalization of the technology.

The industrial boiler contract was awarded to Energy and Environmental Research Corporation (EERC) with a proposed subcontract to a major boiler manufacturer. The utility boiler contract was awarded to Babcock and Wilcox with a proposed subcontract to EERC. Both contracts are scheduled to be completed in late 1982.

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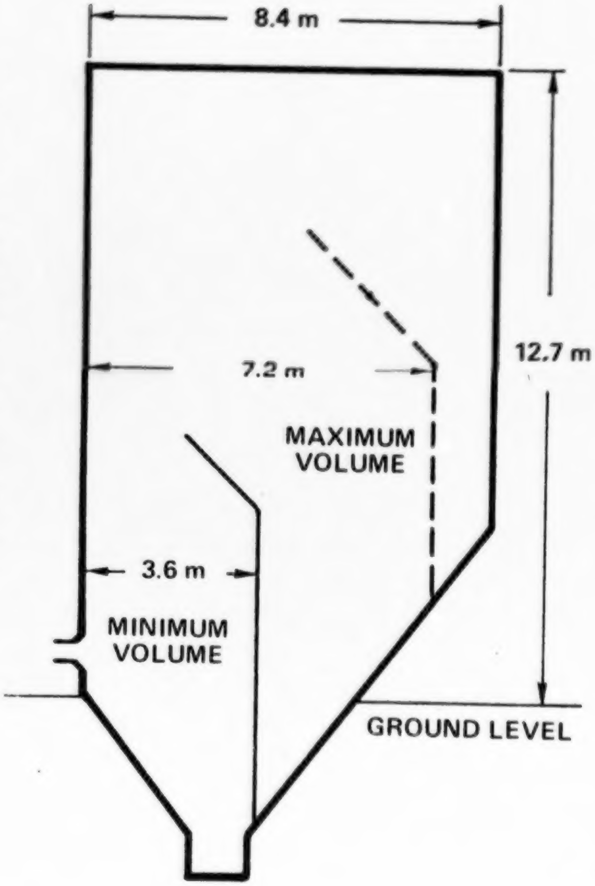
8.4 m
12.7 m
7.2 m
MAXIMUM VOLUME
3.6 m
MINIMUM VOLUME
GROUND LEVEL

- FUELS:
  - PULVERIZED COAL
  - HEAVY OIL
- FIRING CAPACITY:
  - 15 - 40 THERMAL MW (50-120 X 10^6 Btu/hr)
- HEAT RELEASE RATE:
  - 1.6 to 2.4 kW/m^3
- VARIABLE GEOMETRY
- SHEET STEEL WALLS:
  - WATER SPRAY COOLED
- PULVERIZER-RAYMOND CE (MOD 473A):
  - 6000 kg/hr
- AIR PREHEAT TEMPERATURE:
  - 700 K
- INDEPENDENT CONTROL OF ALL AIR STREAMS

Figure 1. Large Watertube Simulator

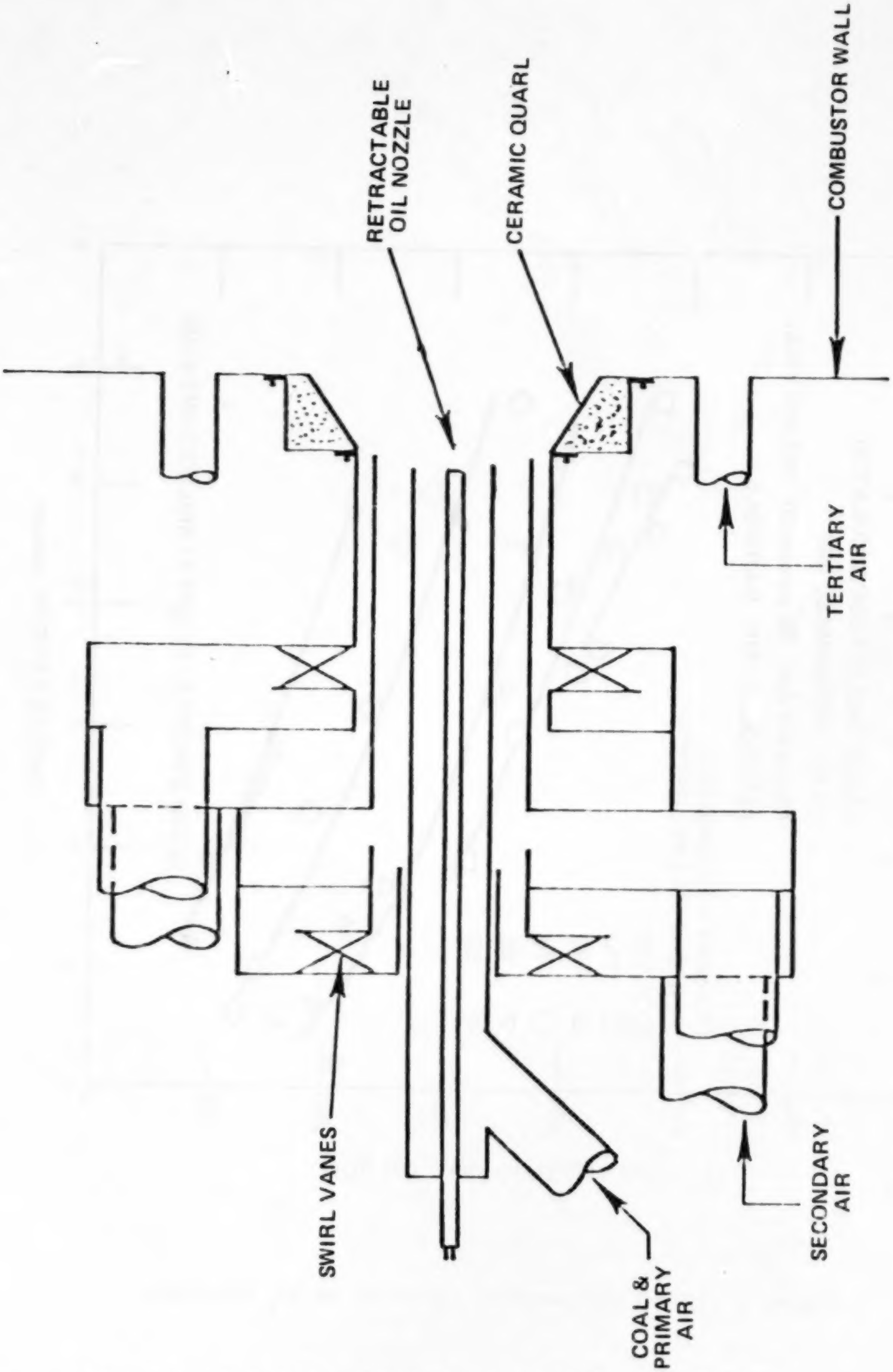
COMBUSTOR WALL
CERAMIC QUARL
RETRACTABLE OIL NOZZLE
TERTIARY AIR
SWIRL VANES
SECONDARY AIR
COAL & PRIMARY AIR

Figure 2. Schematic of Experimental Low NO_x Coal Burner

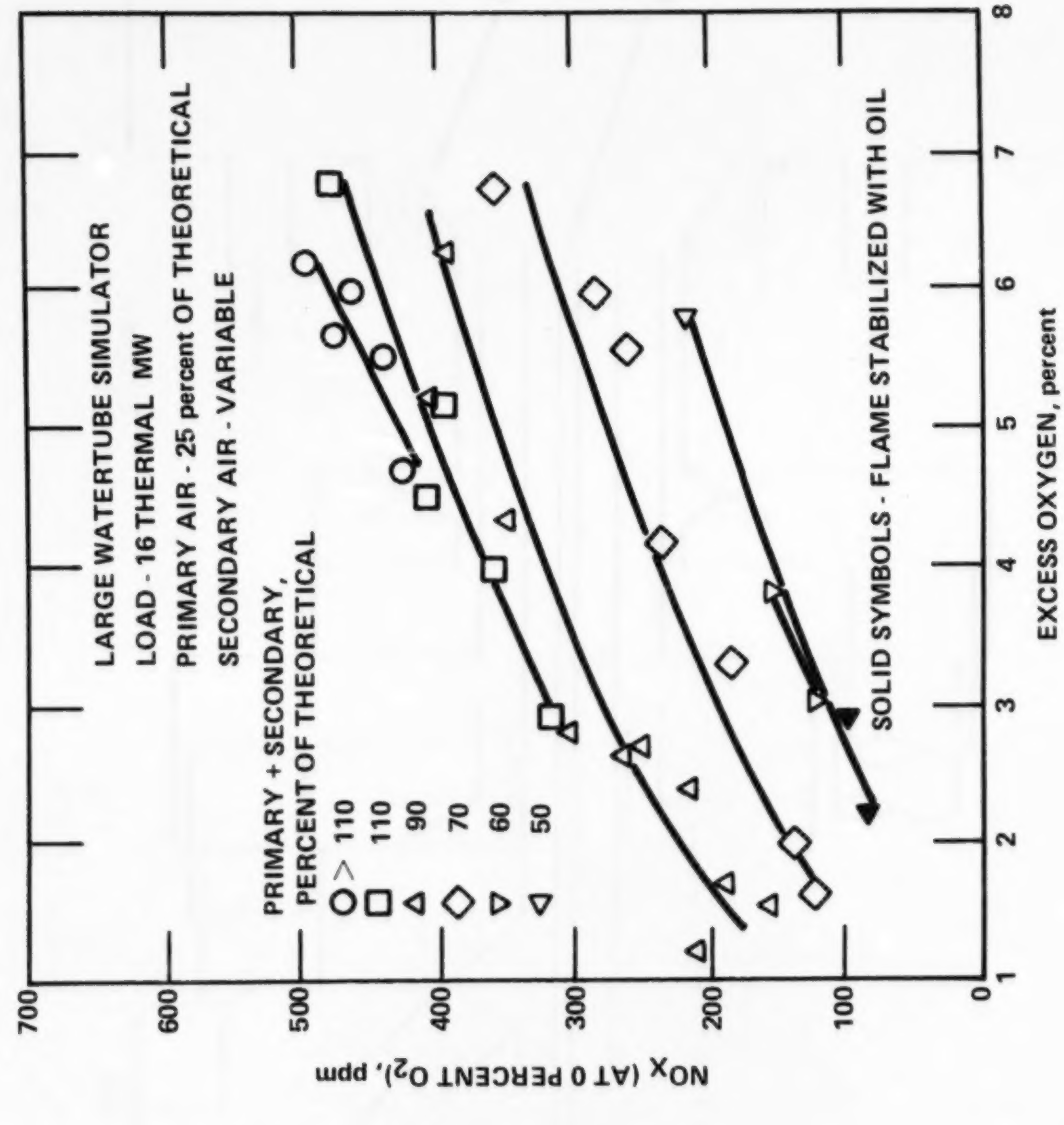

Figure 3. Effect of Operating Variables on NO_x Emissions

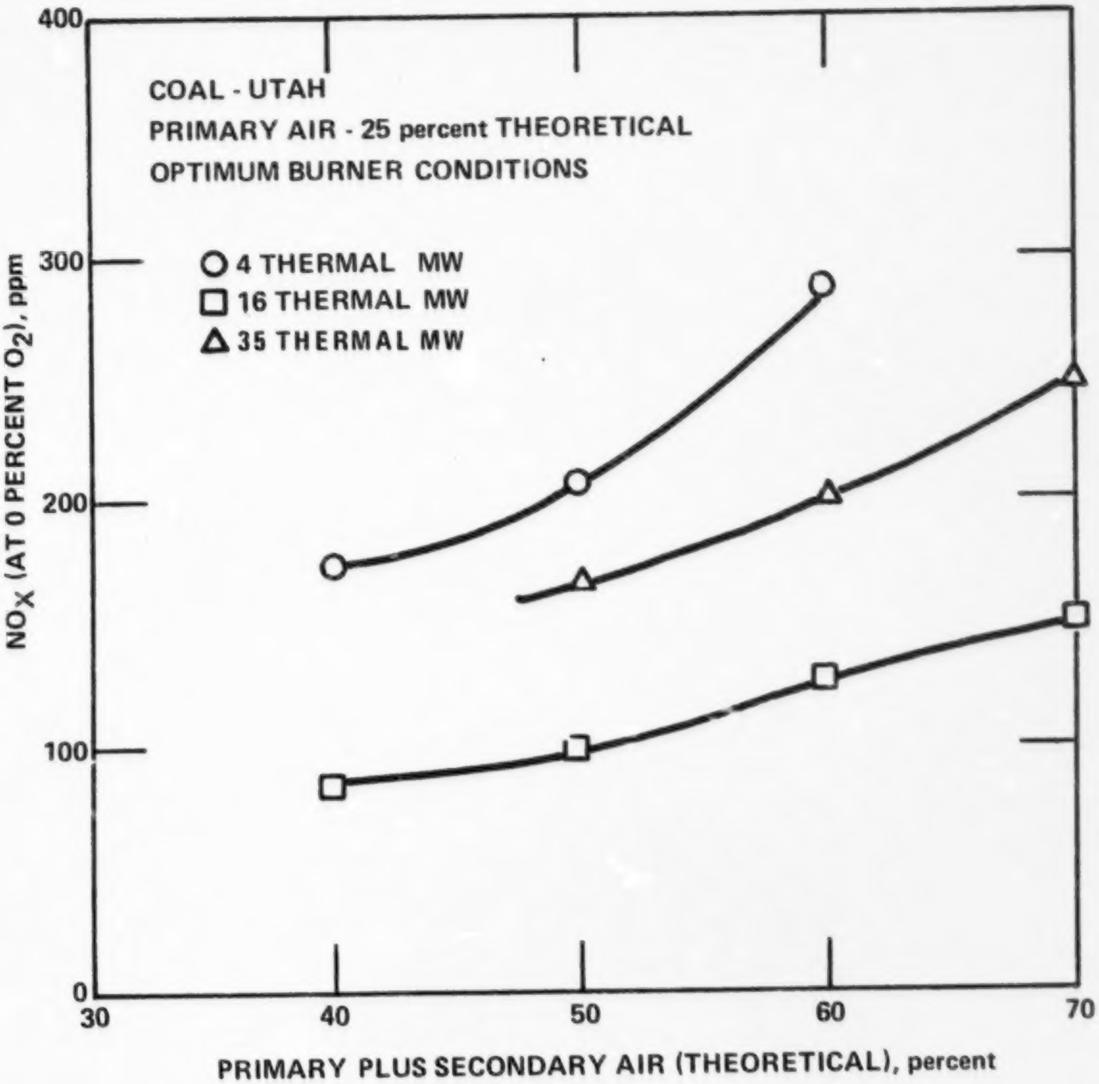

Figure 4. Effect of Burner Scale on NO$_X$ Emissions.

APPLICABILITY OF THE THERMAL DeNO$_x$ PROCESS TO COAL FIRED UTILITY BOILERS

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ABSTRACT

Under an EPA contract, the performance and cost of the Exxon Thermal DeNO$_x$ Process were projected for coal fired utility boilers. In this process, ammonia is injected into boiler convective flue gas passages to reduce NO$_x$ selectively without a catalyst within a critical temperature range. Eight coal fired utility boilers were selected to determine process applicability to boilers of different manufacturers, sizes, firing methods, and by coal types.

Thermal DeNO$_x$ performance was projected both with and without combustion modifications (CM). Assumed NO$_x$ reduction targets were (i) the proposed NSPS of 0.5-0.6 lb. NO$_x$/MBtu, and (ii) a deep reduction level of 0.3 to 0.4 lbs. NO$_x$/MBtu. The maximum practical level of NO$_x$ reduction which could be achieved was also projected. A total of six cases were established. Performance was projected to be equally applicable to all boilers studied at full and one or more reduced loads down to 50%, despite significant differences in flue gas temperature profiles and flow path configurations. Maximum projected Thermal DeNO$_x$ performance ranged between 50 and 59% for the coal fired boilers selected for study. For actual applications, design limitations and operating problems that might limit the level of DeNO$_x$ attainable will have to be assessed in each case.

Budget type cost estimates were prepared for full load. Costs ranged from 0.25 to 1.23 mills/KW-Hr, excluding preliminary engineering costs and licensing royalties. Based on the projected capability of Thermal DeNO$_x$ to supplement CM for reaching low levels of NO$_x$ emissions from coal fired utility boilers, a full scale demonstration program is recommended. The demonstration of Thermal DeNO$_x$ on a coal fired utility boiler would include the potential downstream effects identified from experience with oil fired boilers.

ACKNOWLEDGMENTS

The authors acknowledge the contributions of Messrs. M. E. Tomsho, B. H. Ruterbories and G. J. Smith of Exxon Engineering - Technology Department of Exxon Research and Engineering Co. for their contributions to the engineering assessment reported here. We also acknowledge with thanks the boiler manufacturers, Babcock and Wilcox, Combustion Engineering, Inc., Foster Wheeler Corp., and Riley Stoker Corp., for providing technical information required on their boilers for the assessment of the applicability of Thermal DeNO$_x$ to different boiler types.

INTRODUCTION

This paper presents a summary of an engineering study sponsored by the U.S. Environmental Protection Agency to project the performance and estimate the cost of the Exxon Thermal DeNO$_x$ Process on selected, representative coal fired utility boilers (1). The non-catalytic Thermal DeNO$_x$ Process is based on the selective reduction of NO$_x$ with NH$_3$ in the gas phase. Thermal DeNO$_x$ has been commercially demonstrated on gas-and oil-fired boilers and process furnaces. A pilot scale test on a coal fired combustor produced NO$_x$ reductions similar to those obtained with oil and gas firing (1,2).

The following sections of this paper provide information on the chemistry and engineering considerations which impact on the applicability of the Thermal DeNO$_x$ Process, the methodology used in undertaking the assessment, the projections and results of the study, as well as recommendations for future work.

CHEMISTRY AND ENGINEERING CONSIDERATIONS

The Thermal DeNO$_x$ Process relies on the selective reaction between NH$_3$ and NO$_x$ to produce nitrogen and water (3,4). The reaction requires the presence of oxygen and proceeds within a critical temperature range. The overall NO reduction and production reactions are summarized in equations 1) and 2), respectively;

$$NO + NH_3 + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O \qquad 1)$$

$$NH_3 + 5/4\ O_2 \rightarrow NO + 3/2\ H_2O \qquad 2)$$

In typical flue gas environments, the NO$_x$ reduction shown as equation 1) dominates at temperatures around 950°C (1740°C). At higher temperatures, the NO$_x$ production reaction shown as equation 2) becomes significant, and it dominates at temperatures over about 1000°C (1830°F). As temperatures are reduced below about 900°C (1650°F), the rates of both reactions slow down, and the ammonia flows through unreacted.

In addition to temperature, the process is also sensitive to initial NO$_x$ and NH$_3$ concentrations. The NH$_3$ injection rate is generally expressed as a mole ratio relative to the initial NO$_x$ concentration. Other variables affecting performance are excess oxygen and available residence time at the reaction temperature.

Exxon Research and Engineering Company (ER&E) has found that hydrogen can be used to shift the DeNO$_x$ temperature window to lower levels. The magnitude of this shift is mainly a function of the amount of H$_2$ injected relative to the NH$_3$. At H$_2$/NH$_3$ ratios on the order of 2:1, the NO$_x$ reduction reaction can be forced to proceed rapidly at 700°C (1290°F). By judiciously selecting the H$_2$/NH$_3$ injection ratio, flue gas treatment can be accomplished over the range of 700-1000°C.

Thermal DeNO$_x$ may be applied to boilers for additional NO$_x$ reduction after combustion modifications such as low excess air firing, the use of low NO$_x$ burners, or overfire air ports have been implemented. As Thermal DeNO$_x$ is a post-flame injection process, it is not affected by certain limitations such as derating that may affect the usefulness of CM in retrofit applications. The Thermal DeNO$_x$ process is viewed as an effective supplement to available combustion modification techniques for attaining low NO$_x$ levels for combustion installations that require a high degree of emission control. Although the temperature sensitivity will cause the reaction's effectiveness to vary from one installation to another, the NO$_x$ reduction is essentially independent of the concentration of oxides of sulfur or particulate matter in the flue gas. The specific level achievable is dependent upon a number of factors, including the boiler design, operating mode, and initial NO$_x$ level. Thus, each boiler to which Thermal DeNO$_x$ is applied must be considered on an individual basis.

When applying the Thermal DeNO$_x$ process to commercial equipment, performance is generally limited by the extreme temperature sensitivity of the reaction and its dependence on the local concentrations of reactants, NH_3, NO_x, O_2, and H_2. The Exxon technology provides a means of adapting the chemistry requirements to industrial equipment environments, and maximum practical reductions ranging from 35 to 65% have been achieved by the use of Thermal DeNO$_x$ in retrofit boiler installations.

The Thermal DeNO$_x$ process utilizes proprietary ER&E gas phase mixing technology to rapidly and efficiently mix the small volume of reagents with the hot flue gas. Correct distribution of reactants is required in order to minimize the breakthrough of unreacted ammonia.

Accommodating flue gas temperature variations is important if high DeNO$_x$ rates are to be achieved. Not only does the system have to accommodate flue gas temperature changes caused by normal load and operating variations, but it also must allow for fluctuations across the reaction zone caused by nonuniformities in flow and heat transfer. It follows, therefore, that case-by-case evaluations of flue gas temperatures and local conditions are required for the application of Thermal DeNO$_x$ to each installation considered.

In initial applications, ammonia was injected only into boiler cavities, (boiler regions between tube banks) which can be considered to be isothermal to a first approximation. Subsequent experimentation by ER&E has shown the feasibility of injecting ammonia into boiler tube bank regions as well. Thus, satisfactory NO_x reduction performance could be obtained by locating the injector grid either in the boiler cavity or in tube banks. The ability to inject ammonia at post-combustion boiler locations with temperatures ranging from 760°C to 1000°C has substantially increased the flexibility of the Exxon Thermal $DeNO_x$ process.

The temperature in the post-combustion convective zone of a boiler is shifted by changes in boiler load. For example, as load is reduced from full to 50%, the temperature for optimum Thermal $DeNO_x$ will shift toward the firebox. Depending on the magnitude of this shift, more than one ammonia injection grid may be required in order to obtain $DeNO_x$ coverage over the range of practical boiler loads. Thus, one grid may be adequate for boiler loads between 100% and 70%, while another would cover the 70% to 50% load range. It should be noted, however, that in some cases the use of hydrogen with its ability to lower the $DeNO_x$ temperature window could permit effective $DeNO_x$ over practical boiler loads with only one grid. In other cases, both hydrogen addition and the use of multiple grids may be required to accommodate load changes. A specific case was considered in which the higher reagent costs of operating a single grid with ammonia and hydrogen versus those of ammonia only with two grids (and higher onsite costs) were compared.

The issue of possible by-products associated with the Thermal $DeNO_x$ reaction has been the subject of extensive study (1, 2, 4) and should be further considered in undertaking a full scale test of the Thermal $DeNO_x$ process on a coal-fired utility boiler. For example, the formation, deposition and emissions of ammonium bisulfate should be determined. Also, a comprehensive emissions measurement program should be performed. The presence of ammonium bisulfate and/or ammonia can influence the performance of electrostatic precipitators. Both beneficial and detrimental effects have been reported. Only through a full scale test of Thermal $DeNO_x$ on a coal-fired power plant can its effect on ESP performance be quantified.

Another factor which should be considered is slagging and fouling deposits associated with the firing of coal. These deposits can change the heat transfer characteristics of the boiler and thereby influence the temperature at any given moment in the Thermal DeNO$_x$ reaction zone. This is an important consideration affecting the design of a Thermal DeNO$_x$ system to be installed in a coal-fired boiler. The Thermal DeNO$_x$ system elements must be made compatible with the coal as well as with soot blowing equipment and procedures.

PROGRAM METHODOLOGY

In undertaking this engineering study, eight typical coal-fired utility boilers representative of current coal fired utility boiler systems were selected. The boilers were chosen to permit an evaluation of the Thermal $DeNO_x$ Process on different utility boiler sizes, firing methods and with different coal types (see Table I). Thermal $DeNO_x$ performance and process costs were determined for two NO_x reduction targets:

a. Trimming NO_x emissions to meet the proposed New Source Performance Standards (NSPS) of 0.6 lb. NO_x/MBtu (450 ppm NO_x) for bituminous coal and lignite fired boilers and 0.5 lb. NO_x/MBtu (375 ppm NO_x) for boilers fired with subbituminous coal.

b. Deep reduction in NO_x levels to 0.4 lb. /MBtu (300 ppm NO_x) for boilers fired with bituminous coal and lignite and 0.3 lb. NO_x/MBtu (225 ppm) for subbituminous coal fired boilers.

Also considered was the:

c. Maximum practical reduction in NO_x levels which could be realized by the application of the Exxon Thermal $DeNO_x$ Process. Ratio of NH_3 to initial NO_x level 1.5 to 1 was assumed.

Two initial NO_x levels were considered for each of the above NO_x targets: (i) uncontrolled and (ii) reduced by combustion modifications. A total of six cases were thus established from the combination of the two initial NO_x levels and three target NO_x levels. These cases are:

Case 1. Uncontrolled baseline NO_x; NSPS target
Case 2. Initial NO_x level reduced by CM; NSPS target
Case 3. Uncontrolled baseline NO_x; deep reduction target

Case 4. Initial NO_x level reduced by CM; deep reduction target
Case 5. Uncontrolled baseline NO_x; maximum NO_x reduction
Case 6. Initial NO_x level reduced by CM, maximum NO_x reduction

In addition to the six cases noted above, special sensitivity analyses were performed for flue gas temperature nonuniformity and the use of hydrogen with ammonia to permit load following. Also, the Thermal $DeNO_x$ costs for reaching NO_x levels of 0.3 to 0.4 lb/MBtu were compared with the costs of combustion modifications required to reach these levels.

The selection of the locations where ammonia is to be injected is based on a number of factors which include: flue gas temperature and conditions, flow path geometry, the reaction time available and the suitability of the reaction zone with respect to its dimensions and configuration of the injector grid. A Performance Prediction Procedure developed by Exxon Research and Engineering Company was used to determine the locations of the ammonia injection grids.

The Exxon Performance Prediction Procedure is a multistep calculation procedure which utilizes and/or determines the above noted factors. The calculation procedure can forecast the percent reduction in initial NO_x level which would result from the location of an ammonia injection grid at any number of locations along the flue gas path. For making these projections of Thermal $DeNO_x$ performance for coal fired utility boilers, the required temperature profile, dimensional and other informaiton were supplied by the four U.S. utility boiler manufacturers, Babcock and Wilcox, Foster Wheeler, Combustion Engineering and Riley Stoker. In the case of an actual installation, after the tentative selection of the location(s) of one or more grids using the Exxon Performance Prediction Procedure, an experimental program would be conducted to measure temperature, flow and concentration distributions in the reaction zone. This information would then be used to confirm or adjust as required the injector location selected and would be utilized as input for the final injector design. For this study, two grid locations were selected for each boiler. The grid locations were optimized for 100%, 75% and 50% load.

The cost estimates prepared in this study were designed to illustrate the costs associated with the Thermal DeNO$_x$ process itself. The techniques and procedures used in producing these estimates were the same as would be applied to a more completely defined project. In the cases considered here the projects were not completely specified with respect to a number of factors which could have an impact on costs. In addition, certain costs which are associated with the commercial application of the process such as licensing fees and preliminary engineering and testing costs were not included.

The cost estimates were formulated for the second quarter of 1977 and were assigned a U.S. Gulf Coast location. Where practical, costs were determined for material and labor, and were adjusted to include field labor, overhead and burden.

DeNO$_x$ performance was projected for all boilers at full load and one or more reduced loads. Costs were projected for full load only.

PROJECTIONS AND CONCLUSIONS

The performance of the Exxon Thermal DeNO$_x$ Process was projected to be essentially equivalent for all eight boiler types evaluated, even though significant differences existed in flue gas temperature profiles and flow path configurations among boilers. These differences resulted in the selection of significantly different injection grid locations among the boilers of different manufacturers. The analysis determined that the proposed NSPS of 0.5 lb./MBtu for subbituminous coal and 0.6 lb./MBtu for lignite and bituminous coal could be met by all boilers considered using the Thermal DeNO$_x$ Process. All boilers studied, except the cyclone boiler fired with Lignite could meet the deep reduction targets of 0.3 and 0.4 lb/MBTU using Thermal DeNO$_x$ coupled with available combustion modifications. Table II summarizes the initial and target NO$_x$ levels and projected costs for Cases 1 through 4, while Table III presents predicted NO$_x$ levels and costs for Cases 5 and 6.

It was projected that the ammonia injection grid location would not be effected significantly by assuming a 50°C larger temperature range in the injection plane than that used for baseline calculations. However, a temperature range increase of this size would reduce DeNO$_x$ performance by 5 to 10 percentage points (e.g., from 50% to 40-45%). It was also found that overall NO$_x$ removal costs increased when hydrogen (rather than multiple grids) was used with only one grid to achieve effective DeNO$_x$ performance at less than full boiler loads.

Other specific projections and conlcusion were as follows:

- All units could reach the proposed NO$_x$ NSPS using Thermal DeNO$_x$ alone. Five units could also reach this level using combusiton modifications alone.

- All units except one could meet the deep NO_x reduction target when Thermal $DeNO_x$ was used in combination with combustion modifications. The one exception was the cyclone boiler fired with lignite.

- Projected costs to reach the proposed NSPS from an uncontrolled base level ranged from 0.25 mills/KW-Hr for the 250 MW CE boiler to a high of 1.17 mills/KW-Hr for the lignite fired cyclone boiler. The average cost for all boilers considered was 0.57 mills/KW-Hr, or 0.49 mills/KW-Hr not including the cyclone boiler.

- Four of the eight boilers could reach the deep reduction target using Thermal $DeNO_x$ alone. Costs ranged from 0.38 mills/KW-Hr to 0.83 mills/KW-Hr for these boilers.

- Projected costs to reach the deep reduction target using Thermal $DeNO_x$ with combustion modifications ranged from 0.38 mills/KW-hr to 0.51 mills/KW-Hr, with the average being 0.44 mills/KW-Hr for the seven boilers reaching the target level.

- NO_x reductions ranging from 62% to 76% and averaging 70% relative to an uncontrolled base case could be achieved using Thermal $DeNO_x$ at a maximum practical level in combination with combustion modifications. NO_x levels in the 0.20 to 0.23 lb. NO_x/MBtu range could be realized for most of the boilers. Costs ranged from 0.55 to 1.14 mills/KW-Hr and averaged 0.68 mills/KW-Hr for all boilers studied. With the lignite boiler excluded, the range was 0.55 to 0.67 mills/KW-Hr and the average was 0.61 mills/KW-Hr.

- The costs for onsites and the carrier were found to be proportional to boiler size.

- The total ammonia reagent costs for all cases, normalized for the amount of NO_x removed expressed as $NO2$ (ΔNO_x), were nearly equal for all eight units studied at \$0.09/lb. ΔNO_x. This parameter was considered to be a good overall judgment criterion of the chemical efficiency and economic efficacy of the Thermal $DeNO_x$ process.

- The Exxon Thermal $DeNO_x$ Process was considered to be equally amenable to all units studied.
- The costs for reaching NO_x levels in the 0.3 to 0.4 lb./MBtu range were compared for Thermal $DeNO_x$ and combustion modifications. The costs of most conventional combustion modifications and combinations thereof were lower than that of Thermal $DeNO_x$. Extreme NO_x reduction methods such as derating or staged combustion that incurred derating would be more expensive.

RECOMMENDATIONS

The primary recommendation resulting from this engineering assessment is that a demonstration of the Exxon Thermal $DeNO_x$ Process on a coal fired utility boiler is required to test the process effectiveness and determine potential side-effects under realistic, full scale conditions. After the selection of a suitable candidate boiler, a detailed performance and cost analysis must be prepared. Temperature and velocity profile measurements in the boiler heat transfer region will be required to verify grid placement and performance estimates. After installation and startup of Thermal $DeNO_x$ system, a careful measurement and evaluation program will be needed to assess $DeNO_x$ performance, costs, and potential side effects that may result from the use of the Thermal $DeNO_x$ process.

In undertaking this demonstration, a high level of attention should be accorded to those factors which could reduce the overall effectiveness of the Thermal $DeNO_x$ Process on coal fired utility boilers, or could have adverse side effects on boiler operation or the environment. These factors include:

- Ammonia and by-product emissions
- Effect of slag formation and fouling on $DeNO_x$ reaction zone temperatures, and on resulting $DeNO_x$ performance.
- Effective $DeNO_x$ performance under differing boiler load conditions.
- Effect of deposition of ammonium sulfates on metal surfaces and on electrostatic precipitator performance.
- Compatibility of Thermal $DeNO_x$ system elements with coal ash levels and with soot blowing equipment and procedures.

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TABLE I. BOILERS SELECTED FOR STUDY

Boiler Manufacturer	Firing Method	Boiler Size, MW	Coal Type
Babcock and Wilcox	Front Wall	130	Subbituminous
Babcock and Wilcox	Horizontally Opposed	333	Bituminous
Babcock and Wilcox	Cyclone	400	Lignite
Combustion Engineering	Tangential Single Furnace	350	Bituminous
Combustion Engineering	Tangential	800	Subbituminous
Foster Wheeler	Front Wall	330	Bituminous
Foster Wheeler	Horizontally Opposed	670	Subbituminous
Riley Stoker	Turbo Furnace	350	Bituminous

TABLE II. TARGET CASES FOR REDUCING NO_x EMISSIONS OF COAL FIRED UTILITY BOILERS USING THERMAL $DeNO_x$

				Trim Cases					Deep Reduction Cases					
				Case 1 W/O Comb. Mod.		Case 2 With Comb. Mod.			Case 3 W/O Comb. Mod.		Case 4 With Comb. Mod.			
Manuf.	Size, MW	Firing Type	Coal Type	Initial NO_x, ppm	Cost Mills/KW-Hr	Initial NO_x, ppm	Cost Mills/KW-Hr	Final NO_x, ppm	Initial NO_x, ppm	Cost Mills/KW-Hr	Initial NO_x, ppm	Cost Mills/KW-Hr	Final NO_x, ppm	Percent Reduction From Uncontrolld Case
B&W	130	FW	Subbit.	500	0.49	300	0.06*	375	500	**	300	0.47	225	55
	333	HO	Bit.	700	0.45	420	0.06*	450	700	0.63	420	0.38	300	57
	400	Cyclone	Lig.	1000	1.17	900	0.99	450	1000	**	900	**	300	--
CE	330	Tan	Bit.	500	0.25	450	0.08*	450	500	0.38	450	0.42	300	40
	800	Tan	Subbit.	530	0.34	375	0.08*	375	530	0.62	375	0.42	225	58
F-W	330	FW	Bit.	850	0.71	510	0.33	450	850	**	510	0.50	300	65
	670	HO	Subbit.	700	0.63	420	0.31	375	700	**	420	0.51	225	61
RS	350	Turbo.	Bit.	700	0.54	420	0.10*	450	700	0.83	420	0.45	300	57

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* Thermal $DeNO_x$ not required. Final NO_x level attainable using combustion modifications.

** Target NO_x level cannot be reached.

TABLE III. MAXIMUM PRACTICAL NO_x REDUCTION PREDICTED USING THERMAL $DeNO_x$

	Boiler			Case 5				Case 6				
				Without Combustion Modifications				With Combustion Modifications				
				NO_x				NO_x				
Manuf.	Size, MW	Firing Type	Coal Type	Initial Level, ppm	Final Level, ppm	Percent NO_x Reduction	Total Cost, Mills/KW-Hr	Initial Level, ppm	Final Level, ppm	Percent NO_x Reduction	Total Cost, Mills/KW-Hr	Percent Total NO_x Reduction Possible From Uncontrolled Case
B&W	130	FW	Subbit.	500	250	50	0.71	300	150	50	0.60	70
	333	HO	Bit.	700	290	59	0.70	420	175	58	0.55	75
	400	Cyclone	Lignite	1000	430	57	1.23	900	385	57	1.14	62
CE	350	Tan	Bit.	500	210	58	0.57	450	190	58	0.61	62
	800	Tan	Subbit.	530	230	57	0.62	375	160	57	0.59	70
F-W	330	FW	Bit.	850	390	54	0.82	510	230	55	0.62	73
	670	HO	Subbit.	700	290	59	0.87	420	170	59	0.65	76
RS	350	Turbo	Bit.	700	295	58	0.84	420	175	58	0.67	75

COMBUSTION MODIFICATION CONCEPTS FOR STOKER BOILER APPLICATIONS

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ABSTRACT

This contract program will apply combustion modification concepts investigated in prior government and industry programs to full-scale coal-fired stoker boilers. In Phase I, based on reported field test results and R&D information on combustion modification integrated with a perspective of the stoker boiler spectrum in the United States, a contractor will select and negotiate for the utilization of two representative large industrial spreader stoker systems. Representative fuels (including cleaned or processed fuels) will be selected and used in the study. A comprehensive Operation Plan will be prepared to bring together all elements of the program in a study that will address the problems involved in applying new technology to stoker boilers and include design of the hardware for applying the combustion modification concepts to the specific units selected. While the plan is reviewed for EPA approval, the contractor will conduct the baseline study of the boiler systems to establish the unmodified performance characteristics. After approval of the Operation Plan, the contractor will construct the modifications to the system and proceed with the comprehensive study of the modified system.

The program will continue with analysis of the data and preparation of a thorough evaluation of the environmental aspects of the applied modification concepts. Subsequent to the analysis and evaluation, a document will be prepared in cooperation with boiler owners and manufacturers that will promote application of the results of this program to new design and retrofit installations.

In Phase II, the contractor will apply combustion modifications to other types of stoker systems. Boilers representative of commercial moving grate and underfeed stokers (about three units) will be selected for the program. This phase will consist of the same series of tasks as the large spreader stoker phase, progressing from selection of the boilers and fuels, through planning, design, baseline determination, modification construction, modification testing, comprehensive analysis and evaluation, to guideline document preparation.

An industrial review panel will be established to provide practical guidance for the program and insure that the results would have the maximum benefit in the shortest possible time for stoker boiler manufacturers and owners.